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NUREG-0853
Supplement No. 6

Safety Evaluation Report

related to the operation of
Clinton Power Station,
Unit No. 1

Docket No. 50-461

Illinois Power Company, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

July 1988

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ABSTRACT

Supplement No. 6 to the Safety Evaluation Report on the application filed by Illinois Power Company, Soyland Power Cooperative, Inc., and Western Illinois Power Cooperative, Inc., as applicants and owners, for a license to operate the Clinton Power Station, Unit No. 1, has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. The facility is located in Harp Township, DeWitt County, Illinois. This supplement reports the status of items that have been resolved by the staff since Supplement No. 5 was issued.

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1 INTRODUCTION AND GENERAL DESCRIPTION

1.1 Introduction

The Nuclear Regulatory Commission staff (referred to as the NRC staff or staff) issued its Safety Evaluation Report (SER) (NUREG-0853) in February 1982 regarding the application by Illinois Power Company et al. (hereinafter referred to as the applicant) for a license to operate the Clinton Power Station, Unit No. 1, Docket No. 50-461. Supplement No. 1 (SSER 1) to the Clinton SER was issued in July 1982; SSER 2 was issued in May 1983; SSER 3 was issued in May 1984; SSER 4 was issued February 1985; and SSER 5 was issued in January 1986. The purpose of this sixth supplement (SSER 6) is to further revise the SER by providing results of the NRC staff's review of information submitted by the applicant to address the remaining unresolved issues listed in Sections 1.9 and 1.10 and some of the license conditions listed in Section 1.11 of the SER and its supplements.

Each section and appendix of this supplement is numbered and titled so that it corresponds to the section or appendix of the SER that is relevant to the NRC staff's additional evaluation. Except where specifically noted, the material in this supplement does not replace the material in the corresponding SER section or appendix. Appendix A is a continuation of the chronology of correspondence between NRC and the applicant and makes current the lists in the SER and in SSER 1 through SSER 5. Appendix B is a list of references cited in this report; the availability of the references is described on the inside front cover of this report. Appendix D is a list of principal contributors to this supplement. Appendix F corrects errors in the SER and its supplements. Appendix I, added to the SER in Supplement 5, is amended in this supplement. Appendices L, M, N, and O add four reports to the SER: "Conformance to Generic Letter 83-28, Item 2.1," prepared by EG&G, Idaho, Inc. (Appendix L); "Clinton Quality Assurance Report," prepared by Region III staff (Appendix M); a safety evaluation referring to deferrals beyond fuel load of certain preoperational test items, prepared by the NRC staff (Appendix N); and a safety evaluation referring to Humphrey concerns prepared by the NRC staff (Appendix O).

Copies of this SER supplement are available for inspection at the NRC Public Document Room at 1717 H Street, N.W., Washington, D.C., and at the Warner Vespasian Library, Clinton, Illinois. Copies are also available for purchase from the sources indicated on the inside front cover.

The NRC Project Manager assigned to the operating license application for Clinton Unit 1 is Byron L. Siegel. Mr. Siegel may be contacted by calling (301) 492-9474 or by writing to

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1.9 Outstanding Issues

In SER Section 1.9, the NRC staff identified 20 outstanding issues that had not been resolved at the time the document was issued. SSER 1 reported that 4 of those issues had been satisfactorily resolved and 1 had been changed to a confirmatory status. SSER 2 reported that 6 issues had either been resolved or changed to a confirmatory status. SSER 3 reported that 4 issues had been resolved. SSER 4 partially resolved 1 issue and reopened another. SSER 5 reported that 1 issue had been resolved and added an additional outstanding issue.

The present supplement (SSER 6) resolves 6 outstanding issues and partially resolves 1 outstanding issue. The current status of each of the 21 issues is tabulated below. For those issues discussed in this supplement, the relevant sections in this document are indicated. Resolution of issues that need not be resolved before a low-power operating license is granted will be reported in future supplements. Only Outstanding Issue 7b, "Seismic and Dynamic Qualification of Mechanical and Electrical Equipment," remains to be resolved, and should be resolved before the low-power license is issued.

Issue		Status	SSER 6 Section(s)
(1)	Transportation accidents	Resolved in SSER 3	--
(2)	Effects of Unit 2 excavation	Resolved in SSER 2	--
(3)	Seismic analysis	Became confirmatory issue 70, resolved in SSER 3	--
(4)	Internally generated missiles	Resolved in SSER 1	--
(5)	Postulated piping failures	Resolved in SSER 6	3.6.1 & 3.6.2
(6)	Steady-state vibration acceptance criteria for balance of plant piping	Resolved in SSER 2	--
(7a)	Environmental qualification of electrical and mechanical equipment	Resolved in SSER 5 and SSER 6	3.11
(7b)	Seismic and dynamic qualification of mechanical and electrical equipment	Under review, audit results reported in SSER 5	--
(7c)	Pump and valve operability qualification	Resolved in SSER 6	3.10
	NUREG-0737 Item II.E.4.2(6)	Resolved in SSER 5	
(8a)	Preservice (PSI) and inservice inspection (ISI) programs	PSI program: became confirmatory issue 67 in SSER 1	--

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Issue		Status	SSER 6 Section(s)
(8a continued)		ISI program: became license condition 12 in SSER 2	
(8b)	Preservice and inservice testing of pumps and valves	Became confirmatory issue 68 in SSER 1	--
(9a)	Pool dynamic loads due to LOCA	Resolved in SSER 6	6.2.1.8
(9b)	Pool dynamic loads due to SRV	Resolved in SSER 5	
(10a)	Containment purge	Became confirmatory issue 69 in SSER 2	--
(10b)	Containment isolation	Resolved in SSER 2	--
(10c)	Containment leakage testing (vent and drain lines)	Resolved in SSER 2	--
(10d)	Containment leakage testing (secondary containment)	Resolved in SSER 2	--
(10e)	Containment bypass leakage	Resolved in SSER 2	--
(11)	Control room habitability	Resolved in SSER 1	--
(12)	Engineered safety features reset controls (IE Bulletin 80-06)	Resolved in SSER 2	--
(13)	Remote shutdown system	Resolved in SSER 3 and SSER 6	7.4.3.1
(14)	Capability for safe shutdown following loss of bus supplying power to instruments and controls (IE Bulletin 79-27)	Resolved in SSER 2	--
(15)	Control system failures resulting from high-energy-line breaks or common power source or sensor malfunctions	Resolved in SSER 6	7.7.3.1
(16)	Separation of the RPS and MSIV solenoid circuits and PGCC circuits	Resolved in SSER 1	--
(17)	Organization and staffing	Resolved in SSER 5	--
(18a)	Onsite emergency plan	Resolved in SSER 4	--

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Issue		Status	SSER 6 Section(s)
(18b)	Offsite emergency plan	Resolved in SSER 6	13.3
(19)	Security	Resolved in SSER 1, amended security plans reviewed and approved in SSER 5	--
(20)	QA program	Resolved in SSER 3	--
(21)	Fire Protection Evaluation Report and Safe Shutdown Analysis	Resolved in SSER 6	9.5

1.10 Confirmatory Issues

In SER Section 1.10, the NRC staff identified 66 confirmatory issues for which additional information and documentation were required to confirm preliminary conclusions. SSER 1 reported that 28 of those issues had been satisfactorily resolved. SSER 2 addressed 11 additional issues that had been resolved, as well as certain issues that still required resolution. SSER 3 addressed 9 additional issues that had been resolved. SSER 4 addressed 10 additional issues that had been totally resolved and 2 that had been partially resolved. SSER 5 addressed 9 confirmatory issues that had been totally resolved. The present supplement (SSER 6) resolves the 4 remaining confirmatory issues. The current status of each of the 66 original issues is tabulated below. Four issues (67, 68, 69, and 70) that previously had been outstanding issues in SSER 1 were added to the confirmatory list in SSER 2. Issue 71 was added in SSER 3.

Issue		Status	SSER 6 Section(s)
(1)	Emergency preparedness meteorological program	Resolved in SSER 6	13.3
(2)	Inspection program around the ultimate heat sink (UHS) and the main cooling lake dam	Resolved in SSER 1	--
(3)	Protection of UHS dam abutments against soil erosion	Resolved in SSER 1	--
(4)	Internally generated missiles - fan failures	Resolved in SSER 2	--
(5)	Design adequacy of cable tray system	Resolved in SSER 1	--
(6)	Containment ultimate strength analysis	Removed from list in SSER 4	--

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Issue		Status	SSER 6 Section(s)
(7)	Structural integrity of safety-related masonry walls	Resolved in SSER 2	--
(8)	NSSS pipe break analysis using SRP criteria	Resolved in SSER 1	--
(9)	Vibration assessment of RPV internals	Resolved in SSER 4	--
(10)	Annulus pressurization loads (LOCA asymmetric loads)	Resolved in SSER 4	--
(11)	Use of SRSS for combining Mark III dynamic responses for other than LOCA and SSE	Resolved in SSER 1	--
(12)	IE Bulletin 79-02 regarding support baseplate flexibility	Resolved in SSER 2	--
(13)	Mark III hydrodynamic loads	Became part of outstanding issue 9 to avoid duplication in SSER 4	--
(14)	Feedwater check valve analysis	Resolved in SSER 2	--
(15)	Seismic and LOCA loadings on fuel assemblies (LRG II Issue 2-CPB)	Resolved in SSER 4	--
(16)	Scram discharge system evaluation	Resolved in SSER 1	--
(17)	Fracture toughness data	Resolved in SSER 1	--
(18)	Subcompartment pressure analysis	Resolved in SSER 5	--
(19)	Combustible gas control	Resolved in SSER 3	--
(20)	Containment isolation dependability	Resolved in SSER 2	--
(21)	Containment monitoring, II.F.1(1) through II.F.1(6)	Resolved in SSER 4 and SSER 5	--
(22)	Plant-specific LOCA analysis, II.K.3.31	Resolved in SSER 3	--
(23)	High drywell pressure interlocks	Resolved in SSER 1	--

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Issue		Status	SSER 6 Section(s)
(24)	ATWS recirculation pump trip	Resolved in SSER 6	7.2.3.1
(25)	Response-time testing	Resolved in SSER 1	--
(26)	Analog trip modules and optical isolators	Resolved in SSER 2	--
(27)	Susceptibility of the NSPS to electrical noise	Resolved in SSER 1	--
(28)	Modification of ADS logic, II.K.3.18	Resolved in SSER 4	--
(29)	Restart of low-pressure systems, II.K.3.21	Resolved in SSER 1	--
(30)	Temperature effects on level measurements	Resolved in SSER 2	--
(31)	Containment atmosphere monitoring system	Resolved in SSER 4	--
(32)	Verification that testing is in accordance with BTP PSB-1	Removed from list in SSER 1	--
(33)	Electrical drawing review	Removed from list in SSER 1	--
(34)	Verification of diesel generator testing	Resolved in SSER 4	--
(35)	Class A supervision and power supply for fire detection system	Resolved in SSER 3	--
(36)	Circulating water system	Resolved in SSER 2	--
(37)	Initial test program	Resolved in SER	--
(38)	Human engineering aspects of control room design, I.D.1	Resolved in SSER 5	--
(39)	Common reference for reactor vessel level instruments, II.K.3.27	Resolved in SSER 2	--
(40)	Shielding design review, II.B.2	Resolved in SSER 1	--

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Issue		Status	SSER 6 Section(s)
(41)	Short-term accident and procedures review, I.C.1, I.C.7, I.C.8	Resolved in SSER 4 and SSER 5	--
(42)	Training during low-power testing, I.G.1	Resolved in SSER 5	--
(43)	Review ESF values, II.K.1.5	Resolved in SSER 1	--
(44)	Operability status, II.K.1.10	Resolved in SSER 1	--
(45)	HPCI and RCIC initiation levels, II.K.3.13	Resolved in SSER 4	--
(46)	Isolation of HPCI and RCIC, II.K.3.15	Resolved in SSER 4	--
(47)	Qualification of ADS accumulators, II.K.3.28	Resolved in SSER 5	--
(48)	Plant-specific analysis, II.K.3.30	Resolved in SSER 3	--
(49)	ODYN analysis for River Bend as applied to Clinton	Resolved in SSER 1	--
(50)	Conformance evaluation report for loose-parts monitoring system	Resolved in SSER 3	--
(51)	Requirements of NUREG-0313	Resolved in SSER 1	--
(52)	Control room habitability - chlorine gas	Resolved in SSER 1	--
(53)	Debris screen design	Resolved in SSER 2	--
(54)	Verification of adequacy of fire protection systems	Removed from list in SSER 1	--
(55)	Flood-proof door	Resolved in SSER 2	--
(56)	Valves in fire protection water supply system	Resolved in SSER 1	--
(57)	Break in water supply piping	Resolved in SSER 1	--
(58)	Test data on fire ratings	Resolved in SSER 3	--
(59)	Three-hour-fire-rated penetration seals	Resolved in SSER 3	--

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Issue		Status	SSER 6 Section(s)
(60)	Install fire protection equipment (emergency lighting)	Resolved in SSER 3	--
(61)	Fire protection administrative controls and training	Resolved in SSER 1	--
(62)	Technical Specification on fire protection	Resolved in SSER 1	--
(63)	Periodic leak testing of pressure isolation values	Resolved in SSER 1	--
(64)	Sedimentation in UHS	Resolved in SSER 1	--
(65)	Protection against postulated piping failures	Resolved in SSER 1	--
(66)	Steam bypass of the suppression pool (LRG II Issue 3-CSB)	Resolved in SSER 5	--
(67)	Preservice inspection program	Resolved in SSER 5	--
(68)	Inservice testing of pumps and valves	Resolved in SSER 6	3.9.6
(69a)	Containment low-volume purge system	Resolved in SSER 5	--
(69b)	Low-volume purge valve operability	Resolved in SSER 5	--
(70)	Seismic analysis	Resolved in SSER 3	--
(71)	Humphrey concerns	Resolved in SSER 6	6.2

1.11 License Conditions

In SER Section 1.11, the NRC staff identified nine potential license conditions that may be required as part of the operating license for Clinton Unit 1 to ensure that NRC requirements are met during plant operations. Two additional potential license conditions (10 and 11) were identified in SSER 1, and SSER 2 identified two more conditions (12 and 13), as well as one (6) for which additional requirements were imposed. One condition (14) was added in SSER 3. In SSER 5, 6 potential license conditions (15 through 20) were identified and 11 license conditions were eliminated. Three conditions, (21, 22, and 23), were added in SSER 6. The current status of these issues and the sections in which they are resolved are shown below.

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Issue		Status	SSER 6 Section(s)
(1)	Staffing DeWitt pumping station	Resolved in SSER 5	--
(2)	New stability analysis before second cycle of operation	Resolved in SSER 5	--
(3)	Postaccident monitoring	Resolved in SSER 5	--
(4)	Vacuum relief valve position indication	Resolved in SSER 5	--
(5)	Hydrogen management	Resolved in SSER 6	6.2.7
(6)	Postaccident sampling, II.B.3	Resolved in SSER 5	--
(7)	Diesel generator reliability	Resolved in SSER 5	--
(8)	Kuosheng-1 test program	Resolved in SSER 4	--
(9)	Visual examination of discharged fuel	Resolved in SSER 5	--
(10)	Measurement of groundwater level	Resolved in SSER 5	--
(11)	Security	Resolved in SSER 5	--
(12)	Inservice inspection	Resolved in SSER 5, remains a license condition	--
(13)	Control of heavy loads	Resolved in SSER 5	--
(14)	Transportation accidents	Resolved in SSER 6	2.2.1
(15)	Fuel zone level channels	Added in SSER 5	--
(16)	Partial feedwater heating	Added in SSER 5	--
(17)	Plant operator experience	Added in SSER 5	--
(18)	Emergency facilities and equipment	Resolved in SSER 6	13.3.2.8
(19)	Environmental protection plan for Unit 2 site	Resolved in SSER 6	2.6.1.1
(20)	Detailed Control Room Design Review	Added in SSER 5	--
(21)	Safety parameter display system	Added in SSER 6	7.5.3.2

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Issue	Status	SSER 6 Section(s)
(22) Fire protection	Added in SSER 6	9.5
(23) Control system failures	Added in SSER 6	7.7.3.1

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Table 1.2 Actions required at Clinton Power Station, Unit No. 1, based on generic implications of ATWS events at the Salem plant (Generic Letter 83-28)

Action No.	Action	SSER section
1	POST-TRIP REVIEW	
1.1	Program Description and Procedure	15.2.2.1 (SSER 5)
1.2	Data and Information Capability	15.2.2.1 (SSER 6)
2	EQUIPMENT CLASSIFICATION AND VENDOR INTERFACE	
2.1	Reactor Trip System Components	
2.1.1	Equipment Classification (Part 1)	15.2.2.2 (SSER 6)
2.1.2	Vendor Interface (Part 2)	--
2.2	Programs for All Safety-Related Components	
2.2.1	Equipment Classification (Part 1)	--
2.2.2	Vendor Interface (Part 2)	--
3	POST-MAINTENANCE TESTING	
3.1	Reactor Trip System Components	
3.1.1	Results of Review of Test and Maintenance Procedures and Technical Specifications	15.2.2.3 (SSER 5)
3.1.2	Results of Check of Vendor and Engineering Recommendations	15.2.2.3 (SSER 5)
3.1.3	Identify Post-Maintenance Test Requirements in Existing Technical Specifications Which Degrade Safety	15.2.2.3 (SSER 5)
3.2	All Other Safety-Related Components	
3.2.1	Submit Report Documenting the Extension of Test and Maintenance Procecedures and Technical Specifications Review	15.2.2.3 (SSER 5)
3.2.2	Submit Results of Check of Vendor and Engineering Recomendations	15.2.2.3 (SSER 5)
3.2.3	Identify Post-Maintenance Test Requirements in Existing Technical Specifications	15.2.2.3 (SSER 5)
4	REACTOR TRIP SYSTEM RELIABILITY	
4.1	Vendor-Related Modifications	N/A
4.2	Preventive Maintenance and Surveillance Program for Reactor Trip Breakers	N/A
4.3	Automatic Actuation of Shunt-Trip Attachment for Westinghouse and B&W Plants	N/A

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Table 1.2 (Continued)

Action No.	Action	SSER section
4.4	Improvements in Maintenance and Test Procedures for B&W Plants	N/A
4.5	System Functional	
4.5.1	Test Diverse Trip Features	15.2.2.4 (SSER 5)
4.5.2	Justify Not Modifying the Reactor Trip System to Permit Periodic On-Line Testing	--
4.5.3	Review Existing Intervals for On-Line Functional Testing Required by Technical Specifications	--

Note: N/A = not applicable to Clinton.

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2 SITE CHARACTERISTICS

2.2 Nearby Industrial, Transportation, and Military Facilities

2.2.1 Transportation Routes

The SER identified two hazard categories associated with postulated accidents on the Illinois Central Gulf Railroad near the Clinton Power Station: (1) shipments of flammable compressed gases and (2) shipments of toxic materials. The latter impacts the review and acceptability of the control room habitability systems.

Originally, the applicant had conducted a survey of hazardous materials transported by the railroad. This survey provided the applicant a basis for determining that the railroad did not pose a significant threat to the plant. Because of the lapse of time since the first survey, the applicant, at the staff's request, conducted a second survey and determined that a large number of railroad cars per year traveled over the Illinois Central Gulf Railroad line. The revised traffic level is considerably larger than what was determined during the first survey in terms of numbers and types of hazardous materials.

In light of the potential for significant changes in the hazardous material shipping patterns for this railroad, the staff in Supplement 3 to the SER, recommended a license condition (license condition 14) that would require a periodic survey (every 3 years) of all shipments of hazardous material and a reassessment of the hazards associated with toxic material with respect to the railroad.

In Amendment 36 to the FSAR dated January 1986, the applicant committed to perform a periodic survey of railroad traffic on the Illinois Central Gulf Railroad. The applicant in this amendment committed to the following conditions:

(1) To perform a survey every 3 years.

(2) To submit the initial report to the NRC not later than July 1, 1986.* Subsequent periodic reports shall be submitted to the NRC no later than 60 days after the end of the survey period.

(3) To base the shipping data in the initial report on actual records of shipments made during the calendar year 1985.

(4) With regard to toxic materials, within 6 months of a determination that the original acceptance levels have been exceeded, to provide sensors that will isolate the control room heating, ventilation, and air conditioning system should the identified chemicals present a potential toxic environment.

Since these FSAR commitments are consistent with those recommended by the staff in Supplement 3 of the SER, the staff has determined they are acceptable and license condition 14 is no longer required.

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*The applicant submitted the initial report on June 30, 1986.

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2.4 Hydrology

2.4.4 Hydrologic Evaluation of the Ultimate Heat Sink

Since the initial filling of the cooling lake, the applicant has been monitoring sediment buildup in the submerged ultimate heat sink (UHS) pond. On the basis of monitoring and discussions with the applicant, it was determined that dredging would be required when the sediment volume reached 218 acre-feet, or when the buildup of sediment threatens to block flow between the UHS outlet structure and the screenhouse. The applicant's reevaluation of the 30-day emergency water requirement also contributed to the decrease in the allowable sediment volume from 500 acre-feet to 218 acre-feet.

A technical specification has been written which requires the applicant to develop a sediment and erosion monitoring and dredging program for the UHS. The applicant, by letter dated June 6, 1986, has submitted the administrative program for monitoring and maintenance of the UHS. The staff has reviewed this program and has found it to be acceptable based on the following features:

(1) The program assures that sediment buildup in the UHS does not exceed 218 acre-feet after the autumn of each year.

(2) The program assures that the flow path between the outlet and the screenhouse will not become blocked.

(3) The program includes inspection procedures for determining:

  (a) erosion of the UHS shoreline
  (b) settlement of the UHS dam
  (c) deterioration of concrete structures

(4) The program also alerts the inspecting engineer that acceptance criteria listed in the program do not preclude "good engineering judgment" with respect to localized sediment deposits which could cause problems even though the deposition limits are not exceeded.

2.4.5 Erosion Protection for Cooling Water Canals and Reservoirs

2.4.5.1 Ultimate Heat Sink

The inspection and maintenance program required for the UHS is included in the erosion and sedimentation monitoring program referred to in Section 2.4.4 of this SER supplement. The staff's evaluation and acceptance of the inspection and maintenance program contained in the applicant's June 6, 1986, letter, is also addressed in Section 2.4.4 of this supplement.

2.6 Stability of Subsurface Materials and Foundations

2.6.1 Site Conditions

2.6.1.1 General

In Supplement 5 to the SER the staff proposed a licensing condition (license condition 19) in the Clinton, Unit 1, license that the applicant submit an Environmental Protection Plan for the Clinton Unit 2 site in accordance with the Atomic

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Safety Licensing Board (ASLB) Memorandum and Order dated July 11, 1985, which, upon staff approval, will be incorporated into Appendix B of the Clinton Unit 1 operating license.

By letter dated December 9, 1985, the applicant submitted a revised Environmental Protection Plan for Clinton which is in accordance with the ASLB Memorandum and which the staff has determined to be acceptable. Therefore, license condition 19 is no longer required.

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3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.5 Missile Protection

3.5.1 Missiles

3.5.1.1 Internally Generated Missiles (Outside Containment)

In Sections 3.5.1.1 and 3.5.1.2 of the SER, the staff expressed a concern about the potential for the generation of missiles by certain fans manufactured by the Buffalo Forge Co. The applicant provided information to show that 18 fans have had their housings reinforced to contain any missiles generated by their respective fans. The staff finds this acceptable and considers the concern relating to fans missiles closed.

3.5.1.2 Internally Generated Missiles (Inside Containment)

See Section 3.5.1.1 above.

Floor Grating As a Missile

A construction appraisal team (CAT) inspection was performed at Clinton during May 20-31 and June 10-21, 1985. The results of the inspection were presented in Appendix A of a letter dated August 15, 1985, sent to the applicant. Appendix A of the letter contained an observation that the floor grating inside containment was not fastened to the structural steel. When questioned if the grating could become a missile in the event of a high-energy-line break (HELB), the applicant reported that although the grating would be fastened by clips it could still become a missile when subjected to HELB forces.

In reviewing this issue, the staff asked the applicant to examine areas in the containment to ascertain where the grating could become a missile. In response, the applicant examined those areas in containment where high-energy lines are in close enough proximity to the grating that it is possible for HELB jet impingement to dislodge the grating. The applicant determined that there were two locations wherein a jet from a HELB could actually dislodge grating and cause the grating to move. In both cases, the applicant determined that the grating would not move beyond the limits of the jet from the broken high-energy line because equipment in these areas would obstruct any further passage. The applicant assumed that any equipment impacted by this dislodged grating would be damaged and unusable. The staff considers this a conservative assumption. The staff finds the above analysis acceptable and considers this issue identified during the CAT inspection to be resolved.

On the basis of the above, the staff considers the issues raised by the independent design review (IDR) and CAT inspection in the area of high- and moderate-energy pipe break protection to be resolved and, therefore, this area of review is acceptable.

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3.5.1.3 Tornado Missiles

In response to a staff question regarding the adequacy of 5 inches of reinforced concrete duct 4 feet or more below finished grade for protection against tornado missiles, the applicant responded as follows:

(1) Using the soil penetration equations (Young, 1969), the applicant determined that most of the tornado-generated missiles listed in Table 3.5-4 of the applicant's FSAR did not penetrate the 4 feet of soil cover.

(2) For those missiles capable of penetrating the 4 feet of soil cover, the applicant determined that they would not be capable of penetrating the minimum thickness of reinforced cover, utilizing Equation 3.5-5 in the FSAR.

(3) The applicant performed a probability analysis for those elements for which the soil and/or concrete coverage was less than the required amount. The analysis indicated that the probability of a missile strike for these elements was less than 1×10^{-7}.

The staff finds the foregoing to be acceptable to ensure protection of the plant against tornado missiles.

3.6 Protection Against Dynamic Effects Associated With Postulated Rupture of Piping

3.6.1 Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment

In the Clinton FSAR, the applicant did not provide the results of the pipe rupture analysis for the reactor water cleanup (RWCU) and the control rod drive (CRD) systems. In Amendment 35 to the FSAR, the applicant provided the results of pipe rupture analyses for the RWCU and the CRD systems outside containment. The staff has reviewed FSAR Amendment 35 and evaluated the applicant's program for protecting safety-related components and structures against the effects of postulated pipe breaks in the portions of the RWCU and CRD systems that are located outside containment.

The applicant analyzed breaks or cracks in the RWCU and CRD systems with respect to the effects that they may have on adjacent safety-related components or structures. The analyses were made with respect to jet impingement, pipe whip, and environmental effects for high-energy portions of these systems, and jet impingement and environmental effects for moderate-energy portions of these systems. The applicant relied on physical separation to ensure the protection of safety-related items from breaks in the RWCU system.

The applicant has performed an analysis which demonstrates that the zone of influence of a break in the CRD system is too small to affect any safety-related components. Therefore, breaks were not postulated in the CRD system because of the small size and low energy content in the lines of this system. On the basis of reviews of similar designs, the staff concludes that breaks need not be postulated in the CRD system.

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On the basis of the review described above, the staff concludes that the applicant has adequately calculated the pressure, temperature, and humidity response profiles, that could result from credible breaks and cracks in the RWCU and CRD systems, and used these profiles to develop qualification requirements for equipment and components located within the affected rooms. Furthermore, the staff concludes that the applicant has also adequately considered the effects of single active failures, pipe whip, and jet impingement where applicable.

In the SER, the staff concluded that adequate protection was provided at Clinton against the effects of high- and moderate-energy-line breaks. However, an independent design review (IDR) performed by Bechtel Power Corporation (reported in Section 17 of Supplement 5 to the SER) identified certain pipe-break concerns as requiring additional review. These were identified as Observation Reports (ORs) 55, 57, 64, and 73 in the Bechtel final IDR report dated January 1985. Following a staff inspection of Sargent and Lundy on May 6 through May 9, 1985, the applicant agreed to have Bechtel perform an independent review of both the high-energy-line-break (HELB) and moderate-energy-line-break MELB design to resolve these issues. The results of this review are contained in a Bechtel report dated September 1985.* The staff has reviewed the Bechtel report which addresses the effects of pipe whip and jet impingement on safety-related equipment located outside containment (OR-55), the effects of spray on equipment from MELB (OR-57), the effects of internal flooding from MELB (OR-64), and the effects of pipe whip and jet impingement on safety-related equipment located inside containment (OR-73). The staff's evaluation of these issues is provided below.

Pipe Whip and Jet Impingement on Safety-Related Equipment Outside Containment - OR-55

Bechtel identified concerns in OR-55 that insufficient documentation was available to: demonstrate that physical separation protects essential equipment from the effects of postulated high-energy failures; and demonstrate that divisional separation exists in the RCIC Division I pump room, RWCU pump rooms, RHR heat exchanger A room, and the auxiliary building main steam tunnel. Subsequently, the applicant provided the necessary information to Bechtel to demonstrate acceptable physical and division separation. Finally, Bechtel, in the September 1985 supplementary report, concluded that the physical and divisional separation at Clinton are acceptable.

The staff has independently reviewed the applicant's submittal of the Bechtel supplementary report to determine the validity of Bechtel's conclusions. In addition, the physical and divisional separations were evaluated by the staff using the systems drawing and documentation contained in the safe-shutdown analysis in the Clinton FSAR. This review also indicated that sufficient physical and divisional separation has been provided.

On the basis of the staff's review of the applicant's submittal and the safe-shutdown analysis in the Clinton FSAR, the staff concurs with Bechtel's conclusion that the physical and divisional separation at Clinton protects essential systems from the effects of postulated high-energy line breaks.

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*"Clinton Power Station HELB/MELB Supplementary Review for Illinois Power Company."

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Spray From MELB - OR-57

Bechtel identified a concern in OR-57 regarding the effects of MELB spray on Class 1E equipment. In this regard, the applicant noted, in FSAR Section D.3.6.3, "Moderate Energy Piping," that in areas which contained both high-energy and moderate-energy lines, Class 1E electrical equipment is qualified for the environmental conditions resulting from a postulated high-energy-line break including the effects of spray since the high-energy-line break (HELB) environment bounds that which may result from a MELB. In areas containing only moderate-energy lines, the applicant stated that existing evaluations show that safe shutdown can be achieved by means of either separated redundant equipment or by means of equipment qualified for spray from a MELB. In these evaluations, the applicant also assumed that instrumentation that is sprayed upon from a postulated MELB does not function. The staff finds this acceptable and considers OR-57 to be closed.

Flooding From MELB - OR-64

Bechtel identified a concern in OR-64 regarding flooding effects following a MELB. The staff raised the question with the applicant regarding the use of yield line theory in calculating the effect of flooding upon the structural design of the plant. The applicant confirmed that yield line theory was utilized only to determine moments upon large structural panels affected by flooding. In discussing the effect of flooding, the applicant noted that some block walls were assumed to fall as a result of the interaction of seismic and flooding forces which had been conservatively combined. The applicant reviewed these failures and ascertained that no seismic Category I block wall was involved in such a failure once the forces were separated in accordance with applicable procedures. The applicant also noted that in areas which contained both high-energy and moderate-energy lines, the largest fluid source was evaluated to provide the most conservative flooding analyses. The staff finds this acceptable and considers OR-64 to be closed.

The review also included a control project procedure (Project Instruction PI-CP-75-Rev. 1) requiring responsible engineers to review future design changes that could affect flooding. This instruction requires that a safe-shutdown assessment is to be provided in any safety-related buildings to which safety-related electrical components or water piping in excess of 1 inch are added. The staff has reviewed PI-CP-75-Rev. 1 and finds it acceptable.

Therefore, the staff finds the applicant has properly designed the plant so as to deal with flooding as a result of a break in a high- or moderate-energy line. The Clinton Power Station complies with the requirements of General Design Criterion 4, "Environmental and Missile Design Bases," relating to flooding from internal sources. The staff finds this to be acceptable and considers this concern closed.

Pipe Whip and Jet Impingement on Safety-Related Equipment Inside Containment - OR-73

Bechtel identified a concern in OR-73 regarding the effect of pipe whip and jet impingement on safety-related equipment located inside the containment. Appendix A to the HELB/MELB Supplementary Report (September 1985) identifies IDR open items 6 through 11 as being relevant to OR-73. Appendix B of the HELB/MELB

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Supplementary Report provides the IDR team's detailed supplementary review results of each of these open items. The staff has reviewed these results and has concluded that for IDR open items 6, 7, 8, 9, and 11 contained in the Supplementary Report, the applicant provided sufficient information to respond to each of these issues. On the basis of this information, the staff agrees with the IDR team's conclusions that the applicant has

(1) completed the HELB analysis for all lines inside the drywell (IDR open item 6)

(2) demonstrated that all essential systems and structures remain functional following postulated HELBs (IDR open item 7)

(3) demonstrated that all calculations are current and valid (IDR open item 8)

(4) provided an acceptable design change control program (IDR open item 9)

(5) updated the FSAR to accurately reflect design conditions (IDR open item 11)

A detailed description of the staff evaluation of IDR open item 10 contained in the Supplementary Report, concerning use of NUREG/CR-2913 methodology is presented in Section 3.6.2 of this SSER.

The staff agrees with Bechtel's conclusions, therefore OR-73 is closed.

3.6.2 Determination of Break Locations and Dynamic Effects Associated With the Postulated Rupture of Piping

The SER stated that the applicant had not yet completed the analysis on the effects of jet impingement. This issue was also identified during the Independent Design Review conducted by Bechtel Power Corporation.

The applicant completed the jet impingement analysis and incorporated the results into Amendment 34 of the FSAR, dated July 1985. As stated in FSAR Amendment 34 and in a letter from the applicant dated June 7, 1985, jet impingement analyses performed before April 1, 1984 were based on the procedures outlined in ANSI/ANS 58.2, dated 1980, and Standard Review Plan Section 3.6.2. For certain impingement analyses performed after April 1, 1984, the applicant used a report entitled "Two-Phase Jet Loads" (NUREG/CR-2913) prepared by the NRC contractor, Sandia National Laboratories.

The staff and its consultant, Dr. G. Moses of the University of Wisconsin, have reviewed NUREG/CR-2913 and conclude that only certain portions of the report are acceptable for use on a plant-specific basis. Specifically, the methodology described in the report for calculating jet impingement loads from breaks involving steam and saturated water is acceptable for all distances from the postulated break. The methodology for calculating these loads from breaks involving subcooled liquids is not acceptable at this time.

The staff bases its position on this issue on the uncertainty of the analytical model used by Sandia and the lack of experimental data. In a letter dated December 10, 1985, the applicant clarified the information previously provided in FSAR Amendment 34 and in the June 7, 1985, letter. This clarification confirms that the methodology in NUREG/CR-2913 was not used to calculate forces

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from subcooled water jets and that NUREG/CR-2913 data for pressures outside the applicable range in the report were not extrapolated. The applicant, in Amendment 36 to the FSAR, revised Section 3.6.2 to document this clarification.

On the basis of its review, the staff has concluded that the jet impingement analyses performed by the applicant are acceptable.

Conclusion

On the basis of the acceptable resolution of the items evaluated here (Section 3.6.2) and in Section 3.6.1 of this SER supplement, outstanding issue 5 is resolved.

3.9 Mechanical Systems and Components

3.9.6 Inservice Testing of Pumps and Valves

Because the applicant had not submitted an inservice testing (IST) program for pumps and valves, the SER stated that the resolution of this issue would be addressed in an SER supplement. By a letter dated December 26, 1985, and Revision 1 to that letter dated March 18, 1986, the applicant submitted an IST program.

The staff has not completed a detailed review of the Clinton Unit 1 IST program. A preliminary review was completed and it was found that it is impractical within the limitations of design, geometry, and accessibility for the applicant to meet certain ASME Boiler and Pressure Vessel Code requirements. A delay in the imposition of those requirements will not endanger life or property or the common defense and security of the public. Such a delay is in the public interest, giving due consideration to the burden on the applicant that could result if the requirements were imposed. On the basis of experience at similar plants where no adverse health and safety effects were found, the staff concludes that the requirements of 10 CFR 50.55a(g)(6)(i) are satisfied. If this relief were not granted, the applicant might be forced to curtail the operation of the plant, which constitutes a considerable burden. Therefore, pursuant to 10 CFR 50.55a(g)(6)(i), the relief that the applicant has requested from the pump and valve testing requirements of the 1980 Edition of ASME Code Section XI through Winter 1981 Addenda should be granted for a period of no longer than 2 years from the date of issuance of the operating license or until the detailed review has been completed, whichever comes first. If the review results in additional testing requirements, the applicant will be required to comply with them at that time.

The staff stated in Supplement 1 to the SER that the maximum allowable leakage rate for pressure isolation valves (PIVs) was 1 gpm per valve. Since that time, the staff has approved a more liberal leak rate acceptance criterion of 0.5 gpm per nominal inch of valve size up to a maximum leakage of 5 gpm for any valve. The indexing criteria of ASME Code Paragraph IWV-3427(b) are to be strictly observed. Accordingly, it is expected that the applicant will adopt the new criteria in the Technical Specifications for Clinton Power Station.

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3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

3.10.2 Operability Qualification of Pumps and Valves

3.10.2.1 Introduction

To ensure that the applicant has developed and implemented a program regarding the operability qualification of safety-related pumps and valves, the NRC staff performed a two-step audit. The first step was a review of Section 3.9.3.2 of the FSAR for the description of the applicant's pump and valve operability assurance program. The information provided in the FSAR, however, was general in nature and not sufficient by itself, to provide confidence in the adequacy of the applicant's overall program for pump and valve operability qualification. To provide this confidence, the Pump and Valve Operability Review Team (PVORT), consisting of consultants from a national laboratory and the NRC staff, conducted an onsite audit of a small representative sample of safety-related pumps and valves and supporting documentation.

The criteria by which the audit was performed is described in Section 3.10 of the Standard Review Plan (SRP), and is entitled, "Seismic and Dynamic Qualification of Mechanical and Electrical Equipment." Conformance with SRP Section 3.10 is required in order to satisfy the applicable portions of General Design Criteria (GDC) 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50 as well as Appendix B to 10 CFR 50 and Appendix A to 10 CFR 100.

3.10.2.2 Discussion

In performing the first step of the audit, the NRC staff reviewed the methodology and procedures of the pump and valve operability assurance program contained in Section 3.9.3.2 of the FSAR. The FSAR is general in describing an applicant's pump and valve operability assurance program. To determine the adequacy of the overall program, a site audit was scheduled.

The initial site audit of Clinton Unit 1 was performed the week of August 26, 1985. This effort revealed that the applicant was not fully prepared, nor did the applicant understand the objective of a pump and valve operability review program. As a result, the audit was discontinued and a seminar was held with the applicant to inform it of the objective of the audit and the requirements for operability qualification. It was agreed that a second audit would be performed when the applicant determined that it was prepared. Two significant findings from this first audit were noted: (1) the active valve assemblies were qualified by analysis only and there were concerns regarding the methods used to verify this analysis and (2) the equipment supplied by General Electric (GE), the nuclear steam supply system (NSSS) supplier, was not qualified by GE but by Sargent and Lundy, the architect engineer. Supplement 5 to the SER contains the findings of the initial site audit and identifies the open items remaining to be resolved.

The applicant presented a PVORT recovery program to the NRC on October 21, 1985, which included the approach that the applicant was using to qualify the active valves. The staff agreed in principle with this approach, but would determine if its implementation was applicable during a second audit. Additionally, the

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applicant informed the staff that GE had been retained to address concerns regarding the qualification of the equipment GE supplied. As a result of this meeting, a second audit was performed the week of November 18, 1985. The purpose of this audit was threefold: (1) to determine to what extent the applicant meets the criteria of Section 3.10 of the Standard Review Plan, (2) to determine the adequacy of the pump and valve operability review program developed and implemented, and (3) to address the responses to the generic and specific component concerns identified during the first audit.

As a result of the second audit, the staff concluded that the applicant had made significant improvements in the area of pump and valve operability qualification. However, the staff still had some concerns regarding the methods used to verify the analysis used in the qualification process. Shortly after this audit, the Seismic Qualification Review Team (SQRT) and the PVORT developed a staff position on test vs. analysis that was submitted to the applicant to assist it in addressing this concern. After numerous conference calls and submittals by the applicant, a meeting was held on January 28 and 29, 1986, with the applicant at Sargent and Lundy's office to perform a final documentation audit. As in the case of the second audit, additional information was presented to the staff that previously had not been submitted for review. Therefore, on the basis of information provided by the applicant in submittals dated July 30, August 21, September 24, November 5 and 19, 1985, and March 7, 12, 27, and 31, and April 15 and 18, 1986, in combination with information extracted by the staff, and the preoperational programs implemented, the applicant has satisfied the staff regarding the qualification of the active valve assemblies.

Table 3.1 summarizes the generic concerns identified in the audit process and final disposition. Table 3.2 identifies the equipment audited and final disposition.

3.10.2.4 Conclusion

After inspecting the field installation and reviewing the qualification documents and the responses provided by the applicant to PVORT inquiries and to the SER open items, the staff concludes that a pump and valve operability program has been developed and is being implemented at Clinton, Unit 1 that complies with the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, Appendix B to 10 CFR 50, and Appendix A to 10 CFR 100.

3.11 Environmental Qualification of Electric Equipment Important to Safety and Safety-Related Mechanical Equipment

Section 3.11.5 of Supplement 5 to the Safety Evaluation Report (SSER 5) for Clinton Power Station, Unit 1, lists three items related to environmental qualification requiring resolution before an operating license is issued:

(1) The applicant must notify the staff that the deficiencies cited during the audit have been corrected and all equipment is qualified.

(2) The acceptability of the safety-related mechanical equipment qualification program must be established.

(3) The applicant must notify the staff that the inconsistencies identified in FSAR Tables 3.11-1, -2, -3, and -4 have been corrected.

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A fourth item requiring final staff approval of the applicant's response to the concerns stated in Information Notice 79-22 related to control system failures is addressed as a separate issue in Section 7.7.3 of this supplement to the SER.

The applicant has provided information addressing these three items in letters dated April 4 and February 14, 1986, and in Section 3.11 of the FSAR. These items have been resolved as follows:

(1) The staff has reviewed the corrective actions taken by the applicant and finds that the deficiencies cited during the audit for file EQ CL-009 have been removed by supplementing the file with the necessary additional information.

(2) The applicant has provided a description of the safety-related mechanical equipment qualification program. The results of that program have been submitted for staff review. In addition, qualification documents for four items of safety-related mechanical equipment were submitted for detailed review. In its review, the staff verified that the environmental qualification of safety-related mechanical equipment has been properly established.

(3) The inconsistencies identified in FSAR Tables 3.11-1, -2, -3, and -4 have been corrected as reflected in FSAR Amendment 36.

In SSER 5, the staff reported that, before an operating license is issued, the applicant must notify the staff that all equipment is qualified. Such notification has been provided in the letter from the applicant dated February 14, 1986.

On the basis of the above material and on the results of the previous staff review and audit as detailed in SSER 5, Section 3.11, the staff concludes that Clinton Unit 1 has demonstrated full conformance with the regulatory requirements for environmental qualification. This resolves the outstanding issue 7a.

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Table 3.1 Generic concerns identified in the audit process

Generic items		Identified in audit No.	Status
(1)	Long forms provided have revisions to them but do not indicate this, nor have the approval signatures and dates been changed. This appears to be a QA/QC violation. Additionally, verify that this is not an everyday occurrence thoughout the plant where revisions are made without supporting documentation.	1	Closed
(2)	The qualification documentation is not complete. The July 25, 1985, list should be updated to reflect the actual status of qualification for all pumps and valves under the jurisdiction of this program.	1	Closed
(3)	Components said to be installed and qualified have been turned over to startup for testing (e.g., E22-F001). Audit findings indicated that the qualification package is not for the installed component. Review all installed pumps and valves under the jurisdiction of this program vs. their qualification packages/documentation to ensure this is not repeated elsewhere. Upon completion of this review, provide findings and results.	1	Closed
(4)	Illinois Power has designated Sargent and Lundy (S&L) as being responsible for all pump and valve qualification. However, it appears that S&L does not review all operability concerns regarding qualification, (e.g., (a) Baldwin Associates, Construction Manager, reviews and witnesses compliance with specification; (b) equipment originally supplied by GE (E51-C001 as on entire assembly) was not completely reviewed by S&L which presently has responsibility. How is operability assurance verified and assured by the applicant if its representatives do not review the entire package/documentation that impacts qualification?	1	Closed
(5)	Identify all components (pump and valve) that have been qualified by analysis only. Provide the justification, in lieu of providing verification by test, or identify by what means the analysis has been verified demonstrating operability (see Section 3.10.2.2 for details).	1&2	Closed

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Table 3.1 (Continued)

Generic items	Identified in audit No.	Status
(6) The applicant shall confirm that new loads resulting from LOCA or analysis of as-built conditions applicable to pump and valve under the jurisdiction of this program do not exceed those loads originally used to qualify the equipment.	1	Closed
(7) As a result of the two audits, three valves have been found to have bent, twisted, or experienced stem failures. The applicant should perform an investigation/evaluation to determine the total number of valves with this problem and the root cause. The results of this effort are to be categorized and submitted.	2	Closed
(8) Valves FC-015A, 015B, and 024 were found to have damage to the operator key valve shaft connection. This was attributed to the manual stops on the actuator not being properly adjusted. However, the root cause was never determined. The applicant should perform an evaluation/survey to determine if there is any other valve assembly (valve and actuator) that had or may have this improperly adjusted manual stop to ensure that there is no damage and operability is not impaired.	2	Closed

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Table 3.2 Audited equipment and finding

Plant ID number	NSSS or BOP supplied	Description	Safety function	Component	Manufacturer	Model	Finding/ Resolution	Status
1FC004A&B	BOP	8-in. globe valve with pneumatic actuator (fuel pool cooling and cleaning system)	Open during accident conditions	Valve	Fisher Controls	ED-8	Satisfactory	Closed
				Actuator	Fisher Controls	657-NS		
1B21-F037A	BOP	10-in. wafer style check check valve-vacuum relief (main steam system)	Opens to provide vacuum relief in MSRV discharge necessary following SRV discharge	Valve	Anderson Greenwood Co.	CV1B1030 SCR-N-8	Satisfactory	Closed
			Closes before next blowdown					
1E51-F015	BOP	2-in. self-contained pressure-regulating globe valve (RCIC system)	Control flow of cooling water to RCIC turbine lube oil cooler	Valve	Target Rock Corp.	81-DD-01	Satisfactory	Closed
1E21-C002	BOP	Water leg pump (LPCS system)	Keeps LPCS and RHR loop "A" piping pressurized to avoid water hammer and system delay	Pump	Goulds Pumps Inc.	3196ST centrifugal	Satisfactory	Closed
				Motor	Reliance Electric	215T frame		
1E12-F073A	BOP	1½-in. globe valve with motor-operated actuator (RHR system)	Open for venting RHR heat exchanger	Valve	Yarway Corp.	FIG. No. 5515B-SA105M	Satisfactory	Closed
			Closed for containment isolation	Actuator	Limitorque	SMB-000-2		
B21-F067	BOP	1½-in. motor-operated valve (main steam system)	Normal - controls the elimination of condensate in main steam line	Valve	Rockwell Edward	15104-MLPT1	Satisfactory	Closed
				Actuator	Limitorque	SMB-00-10		
SX-01-PC	BOP	Vertical 2-stage pump (shutdown service water system)	Normal - standby safety function, provides cooling water to equipment served by Div. 3	Pump	Bingham Willamette	8x14 A VCM	Satisfactory	Closed
				Motor	Siemens Allis	404VP frame		
1HG010C	BOP	Vacuum relief valve valve (containment drywell)	Minimizes drywell containment negative differential pressure	Valve	GPE Controls	L-D240	Satisfactory	Closed
E22-F010	NSSS	10-in. motor-operated globe valve (HPCS system)	Opens for surveillance testing of HPCS pump	Valve	Anchor Darling	Not provided	Satisfactory	Closed
			Normally closed	Actuator	Limitorque	SMB-4-200		

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Table 3.2 (Continued)

Plant ID number	NSSS or BOP supplied	Description	Safety function	Component	Manufacturer	Model	Finding/ Resolution	Status
E22-F004	NSSS	10-in. motor-operated gate valve (HPCS system)	Permits HPCS system flow to reactor	Valve	Anchor Darling	Not provided	Satisfactory	Closed
				Actuator	Limitorque	SB-3		
E22-F001	NSSS	16-in. motor-operated gate valve (HPCS system)	Normally open, providing a flow-path from RCIC storage tank upon initiation of HPCS	Valve	Anchor Darling	2991-3	Qualification documentation not reviewed	Not reviewed
				Actuator	Limitorque	SMB-00-10		
E22-F005	BOP	10-in. exercisable-testable valve (HPCS system)	Normally closed and acts as pressure boundary - valve opens on HPCS flow	Valve	Anchor Darling	Exercisable tilt disk check valve	Satisfactory	Closed
E51-C001	NSSS	Turbine centrifugal pump (RCIC system)	Standby and to provide flow to RPV on initiation of RCIC	Pump	Bingham Willamette	6x6x10 1/2 CP-4 stage	Satisfactory	Closed
				Turbine	Terry Steam Turbine Corp.	Type ES-2		
SX-01-PA	BOP	Deep draft pump (shutdown service water system)	Normally in standby condition provides cooling water to equipment serviced by the shutdown cooling water piping system	Pump	Borg Warner	37 KXL 2 stage V.C.T.	Satisfactory	Closed
				Motor	Allis Chalmers	8-5D17-90307-1-1		
E51-F063	BOP	8-in. flex wedge gate valve motor operated (RCIC system)	Normally oper providing steam path to RCIC turbine Closes on containment isolation and reopens for RCIC operation	Valve	Anchor Darling	Not provided	Satisfactory	Closed
				Actuator	Limitorque	SMB-0		
FC-13B	BOP	Tilting disk check valve (fuel pool cooling cleanup system)	N/A	Valve	Anchor Darling	Not provided	Component identified by utility as being non-active	Not reviewed
HG-010C	BOP	Vacuum relief valve (containment drywell)	Opens to mix the drywell and containment atmosphere	Valve	GPE Controls	LD240 420	Qualification documentation was not reviewed.	Not reviewed

ASSET SCOPE ANALYSIS

Table 3.2 (continued)

Plant ID number	NSSS or BOP supplied	Description	Safety function	Component	Manufacturer	Model	Finding/ Resolution	Status
1E12-F021	BOP	14-in. motor-operated globe valve (RHR/LPCI system isolation)	Isolates RHR loop "C" test return piping from LPCI injection piping	Valve Actuator	Anchor Darling Limitorque	Not provided SMB-2-40	Satisfactory	Closed
1CC050	BOP	6-in. motor-operated valve (component cool-water system)	Closes to provide containment isolation inside the drywell	Valve Actuator	Anchor Darling Limitorque	Flex wedge SMB-000-2	Satisfactory	Closed
1CC076B	BOP	14-in. motor-operated butterfly valve (component cooling system)	Closes to isolate component cooling water from fuel pool cleanup heat exchanger	Valve Actuator	Posi-Seal Limitorque	Not provided H1BC-SMB-000-2	Satisfactory	Closed
1SX025B	BOP	2-in. motor-operated ball valve (shutdown service water system)	Opens post-LOCA to maintain service water flow to switchgear heat removal unit	Valve Actuator	Jamesbury Corp. ITT General Controls	Not provided NH-91	Qualification documentation was not reviewed during	Not reviewed

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6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

In a letter dated May 8, 1982, Mr. J. Humphrey, a former General Electric (GE) engineer, notified Mississippi Power and Light Company (MP&L) of certain safety concerns regarding the Grand Gulf Mark III containment design. The staff met with MP&L, GE, and Mr. Humphrey to determine the character of these concerns and to establish an appropriate program for their resolution. A number of other Mark III plant applicants attended the meeting, including representatives of the applicant for the Clinton Power Station.

The staff has reviewed the information supplied by the applicant for Clinton. These letters contain the applicant's responses to all the Humphrey concerns. Additional sources of relevant documents reviewed by the staff are listed in the "References" section at the end of the specific evaluations.

There are 66 individual Humphrey concerns covering 22 major areas (referred to as Action Plans by the Mark III Containment Issues Owners Group (CIOG)). Brookhaven National Laboratory (BNL) assisted the staff in evaluating several Humphrey concerns. The staff has endorsed the evaluation of those items that were provided by BNL. Appendix O of this supplement to the SER contains the staff evaluation of the Humphrey concerns and closes all of them, therefore resolving Confirmatory Issue 71.

6.2.1 Containment Functional Design

6.2.1.8 Pool Dynamic Loads

In Supplement 4 to the SER, the staff stated that SRV in-plant tests were not required for Clinton in view of the fact that similar tests would be conducted at Grand Gulf and that the containments at the two units are similar. If the Grand Gulf in-plant tests identified any specific concerns, the applicant would be required to assess any associated impacts on the Clinton design. In a letter dated October 24, 1985, the applicant made a comparison of the Grand Gulf Station test data and Kuosheng station test data with the Clinton containment design and found that there are substantial margins in the safety/relief valve (SRV) discharge loads and that their effects on Clinton are basically as predicted. On the basis of this assessment, the applicant concluded that SRV hydrodynamic loads have been adequately considered in the Clinton design and additional in-plant tests are not required. The staff has reviewed the information provided in the October 24, 1985, letter and concurs with applicant's conclusion.

6.2.1.8.1 LOCA-Related Pool Dynamics

The Mark III pool dynamic loads were reviewed at the construction permit stage for Grand Gulf Nuclear Station, Units 1 & 2 (Grand Gulf 1/2) and at the preliminary design approval stage for GESSAR-238NI. The staff concluded at the time that the information available was sufficient to adequately define the pool dynamic loads for applications for construction permits. Since the issuance of the GESSAR-238NI Safety Evaluation Report (SER) (December 1975), the General

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Electric Co. (GE) conducted further tests and analyses to confirm and refine the original load definitions. To keep the NRC and Mark III applicants apprised of the current status of these tests, GE issued an Interim Containment Loads Report (22A4365) in April of 1978 and revised this report several times before GESSAR II was provided to the staff in March 1980, which is GE's final design approval submittal for its standard balance-of-plant design and is to be referenced by Mark III operating license applicants. Appendix 3B of GESSAR II provides the final pool dynamic load definition for Mark III containments, and is the basic document used for review by the staff and its consultants.

The applicant has incorporated the essential features of Appendix 3B of GESSAR II in various sections of its FSAR submittal. Except as noted below, the applicant has adhered to all analytical techniques, assumptions, methodologies, and concepts contained in Appendix 3B of GESSAR II. Where parameters unique to Clinton differ from those of the GE standard plant, Clinton parameters are used. The staff has reviewed GE's pool dynamic load evaluation to arrive at a final hydrodynamic load definition that can be utilized by Mark III containment applicants for operating licenses. The pool dynamic loads were reviewed under Task Action Plan (TAP) B-10, "Behavior of BWR Mark III Containment." The results of this review are documented in NUREG-0978, "Mark III LOCA-Related Hydrodynamic Load Definition." They have been determined to be applicable to the Clinton Power Station.

Description of Phenomena

Figure 6.1 shows the sequence of events occurring during a design-basis accident (DBA) and the related potential loading conditions. Following a postulated loss-of-coolant accident (LOCA), the drywell pressure increases because of blowdown of the reactor system. Pressurization of the drywell causes the water initially standing in the vent system to be accelerated into the pool and the vents are cleared of water. During this vent-clearing process, the water leaving the horizontal vents forms jets in the suppression pool and causes water jet impingement loads on the structures within the suppression pool and on the containment wall opposite the vents. During the vent-clearing transient, the drywell is subjected to a pressure differential and the weir wall experiences a vent-clearing reaction force.

Immediately following vent clearing, an air and steam bubble forms at the exit of the vents. The bubble pressure initially is assumed equal to the current drywell pressure. This bubble theoretically transmits a pressure wave through the suppression pool water and results in loading the suppression pool boundaries and equipment located in the suppression pool. As air and steam flow from the drywell becomes established in the vent system, the initial vent exit bubble expands to suppression pool hydrostatic pressure. GE Large-Scale Pressure Suppression Test Facility (PSTF) tests show that the steam fraction of the flow is condensed, but continued injection of drywell air and expansion of the air bubble result in a rise in the suppression pool surface. During the early stages of this process, the pool swells in a bulk mode (i.e., a slug of solid water is accelerated upward by the air). During this phase of pool swell, structures close to the pool surface will experience loads as the rising pool surface impacts the lower surface of the structure. In addition to these initial impact loads, these same structures will experience drag loads as water

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flows past them. Equipment in the suppression pool will also experience drag loads.

After the pool surface has risen approximately 18 feet above the initial pool surface, the thickness of the water ligament (top of the air bubble to the pool surface) has decreased to 2 feet or less and the impact loads are significantly reduced. This phase is referred to as incipient breakthrough (i.e., the ligament begins to break up). To account for possible nonconservatisms in the test facility arrangement, the staff has determined that the initiation of breakthrough should be set at 18 feet above the initial pool surface.

Ligament thickness continues to decrease until complete breakthrough is reached and the air bubble can vent to the containment free space. The breakthrough process results in formation of an air/water froth and, for load definition purposes, is defined to happen at 19 feet over the initial surface. The incipient breakthrough height and the height at which froth loads begin, have been set higher than predictions from test results to ensure conservatism. Continued injection of drywell air into the suppression pool results in a period of froth pool swell. This froth swell impinges on structures it encounters, but the two-phase nature of the fluid results in loads that are much smaller than the impact loads associated with bulk pool swell.

When the froth reaches the elevation of the floors on which the hydraulic control units for the control rod drives are located (approximately 22 feet above pool level), the froth encounters a flow restriction with an approximately 25% open areas. The froth pool swell experiences a two-phase pressure drop as it is forced to flow through the available open areas. This pressure differential represents a load on both the floor structures and on the adjacent containment and drywell walls. The result is a discontinuous pressure loading at this elevation.

As drywell air flow decreases through the horizontal vent system, and the air/water suppression pool mixture experiences gravity-induced phase separation, upward movement in the pool stops and the fallback process starts. During this process, floors and other flat structures experience downward loadings, and the containment wall theoretically can be subjected to a small pressure increase. However, this pressure increase has not been observed experimentally.

The pool-swell transient associated with drywell air venting to the pool typically lasts 3 to 5 seconds. Following this, there is a long period of high rate of steam flow through the vent system; data indicate that this steam will be entirely condensed in a region right at the vent exits. For the DBA reactor blowdown, steam condensation lasts for a period of approximately 1 minute. Potential structural loadings during the steam condensation phase of the accident have been observed, and are included in the containment loading specification.

As the reactor blowdown proceeds, the primary system is depleted of high fluid inventory and the steam flow rate to the vent system decreases. This reduced steam flow leads to a reduction in the drywell/containment pressure differential which, in turn, results in a sequential recovering of the horizontal vents. Suppression pool recovery of a particular vent row occurs when the vent stagnation differential pressure corresponds to the suppression pool hydrostatic pressure at the row of vents.

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Toward the end of the reactor blowdown, flow from the top row of vents is capable of condensing the reduced blowdown flow and the two lower rows will be totally recovered. As the blowdown steam flow decreases to very low values, the water in the top row of vents starts to oscillate causing what has become known as vent chugging. The action results in dynamic loads on the top vents and on the weir wall opposite the upper row of vents. In addition, an oscillatory pressure loading condition can occur on the drywell and containment. Since this phenomenon is steam mass-flux dependent (the chugging threshold appears to be in the range of 10 lb/sec/ft^2), it is present for all break sizes. For smaller breaks, it is the only mode of condensation that the vent system will experience.

Shortly after a DBA, the emergency core cooling system (ECCS) pumps automatically start up and pump condensate water and/or suppression pool water into the reactor pressure vessel. This water floods the reactor core and then starts to cascade into the drywell from the break (the time at which this occurs depends upon break size and location). Because the drywell is full of steam at the time of vessel flooding, the sudden introduction of cool water causes rapid steam condensation and drywell depressurization. When the drywell pressure falls below the containment pressure, the drywell vacuum relief system is activated and air from the containment enters the drywell. Eventually, sufficient air returns to equalize the drywell and containment pressures. However, during this drywell depressurization transient, there is a period of negative pressure on the drywell structure. A conservative negative-load condition is, therefore, specified for drywell design. Theoretically, this condition can lead to the flow of water over the weir wall. Structures located in the vicinity could then experience drag and impact loads. Load definitions to account for these effects are included.

Small breaks, defined as breaks not large enough to automatically depressurize the reactor, do not result in bounding pool dynamic loads except for the thermal loading conditions on the drywell and weir walls. Thermal gradient load definitions are provided for the design of the walls containing the suppression pool.

Pool Dynamic Load Assessment

(1) Generic Load Definition

The staff's review of the generic LOCA-related pool dynamic load definition was completed early in 1984. The results of this review and the staff's evaluation of the pool dynamic load definition are documented in NUREG-0978, "Mark III LOCA-Related Hydrodynamic Load Definition," which was published in August 1984. With only a few exceptions, the staff found the load definition proposed by GE in Appendix 3B of GESSAR II to be acceptable. A set of acceptance criteria was developed by the staff to cover those areas where the proposed loads were not considered satisfactory. These were included as Appendix C of NUREG-0987. A brief description of these acceptance criteria is provided below:

(a) Pool Swell Velocity - Pool swell velocity controls impact and drag loads on the structures between the pool at rest elevation and the breakthrough elevation. GESSAR II proposes a value of 40 fps at all elevations. The staff requires use of an elevation-dependent value

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which varies continuously from zero up to a maximum of 50 fps at elevations greater than or equal to 10 feet above the initial pool surface.

(b) Pool Swell Loads on Structures Attached to the Containment Walls - The GESSAR II specification corresponds to steady-state drag at a fixed velocity of 40 fps. The staff's acceptance criteria recommend this to be modified to reflect the change in pool swell velocity given in 1a above, and the inclusion of impact-type forces when the structure is not immersed before pool swell. A detailed procedure for evaluating the impact load is provided in the acceptance criteria.

(c) Bulk Impact on Small Structures - The GESSAR II methodology was found acceptable, provided the structures involved satisfied certain limitations related to structural natural frequency, size, and location above the pool. The acceptance criteria require that when any of these limitations are not satisfied, the load specification be reviewed by the staff on a plant-unique basis.

(d) Froth Impact Loads - The GESSAR II methodology was found to be unacceptable. An acceptable alternative was developed by the staff and its consultant, and is described in detail in the acceptance criteria. The alternative method differs from the GESSAR II approach with respect to maximum froth impact pressure, temporal characteristics of the forcing functions and region of application.

(e) Drag Loads - The GESSAR II methods were found acceptable, provided that they were suitably modified to account for the change in pool velocity given in 1a above, and that they account for the structure-wall interaction effect on drag loads.

(f) Loads on Submerged Structures - The GESSAR II methods were found acceptable, except for computation of acceleration loads on noncylindrical structures and the evaluation of standard drag during the condensation oscillation (CO) phase of the LOCA. The staff required that the Mark I acceptance criteria as described in NUREG-0661 be used to develop these loads.

(g) Impact Loads on Structures Above the Weir Annulus - The GESSAR II methods were found to be acceptable, except for radial structures within 1 foot of the top of the weir wall and all structures located between zero and 0.25 foot above the weir wall. Detailed procedures for evaluation of the impact loads in these cases are provided in the acceptance criteria.

(2) Clinton Power Station Plant-Unique Load Evaluation

(a) Applicability of Generic Load Definitions - The staff has examined the information supplied in the FSAR and has concluded that the generic load definition described in GESSAR II, as modified by the staff's acceptance criteria described in NUREG-0978, is applicable to the Clinton plant except as noted below. All major structures and components that would experience LOCA-related pool dynamic loads are within the range of applicability of the staff-approved methodology

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in terms of geometry and relative location in the containment and the suppression pool. The major features of the suppression pool geometry (main vent submergence and vertical spacing, pool radial width, and pool depth) differ slightly from the standard plant dimensions, but these differences are not considered significant in terms of their effect on pool dynamic loads. The applicant's use of the generic methodology to develop the LOCA-related pool dynamic load definition is, therefore, acceptable.

(b) Plant-Unique Load Definition

(i) Weir Swell Motion During Negative Drywell Pressure

The applicant's design method differs in significant ways from that recommended in GESSAR II (Section 3B.5.1.5). The differences are primarily in the assumptions that are made to develop a set of equations describing weir swell behavior. A detailed description of these differences has been provided by the applicant in an attachment to the applicant's letter (U-600265) to the staff (January 16, 1986).

Generally speaking, the differences are such that the applicant's assumptions are less conservative than those made to develop acceptable GESSAR II load definitions. The result is weir swell behavior that is significantly less severe. Peak steady-state velocities, for example, are reduced from 30 fps to about 18 fps, and maximum swell elevation from 13 feet to about 5 feet. The jet front impact velocity is also reduced somewhat (from 10 to about 9 fps).

The staff has reviewed the applicant's analysis in detail and finds that, although less conservative than the GESSAR II methods, it still preserves significant margins, i.e., the applicant's method may be characterized as a conservative application of conventional first principles using reasonable approximations to render the analysis tractable. The staff finds the method acceptable for characterizing the dynamics of the weir swell motion during conditions of negative drywell pressure.

(ii) Weir Drag Loads During Negative Drywell Pressure

The applicant's method differs from that recommended in GESSAR II (Section 3B.5.1.1) for rectangular structures. GESSAR II requires the use of drag coefficient $C_D = 1.2$ together with the use of an equivalent diameter equal to the diameter of the circle that circumscribes the reactangle. The applicant's method employs the experimental correlations of Bostock and Mair (1972) and Bearman and Trueman (1972). The staff and consultants have examined the applicability of this correlation for the present purpose and conclude that it implies higher loads than those dictated by the staff-approved GESSAR II for most structure geometries and the orientation of practical interest. For these reasons the staff finds the proposed method acceptable.

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(iii) Impact Loads on Structures Between the Pool Surface and the HCU Floors

This item corresponds to Section 3B.10.1 of the GESSAR II load methodology. The applicant indicates that the GESSAR II methods of this section, as modified by the draft acceptance criteria, were the design basis for certain structures which are affected by the modification. The modification required that, for structures less than 4 feet long, the pulse duration be reduced by a factor x/4 where x is the actual length of the structures, and for structures closer than 6 feet above the pool surface, the pulse duration was to be reduced by a factor y/6 where y is the actual elevation of the structure above the pool.

Since the draft criteria have been superseded by the guidance of Appendix C of NUREG-0978, the applicant performed an evaluation using a methodology intended to meet the staff's guidance. This new evaluation would then be used to demonstrate, for relevant structures, that the new methods imply loads that are less than those originally used for design, thereby verifying its adequacy.

A description of the new method was presented in a technical report produced by Burns and Roe, Inc. (attachment to applicant's letter U-600020 to the staff, May 16, 1985). The impact loading for each component is determined as follows:

(1) Determine properties of small structure under consideration, including:

- Orientation (radial or circumferential)
- Width: W in inches
- Height (of structure's bottom) above suppression pool: H in feet
- Length: L in feet
- Dominant vertical natural period (usually the vertical fundamental natural period): T in seconds

(2) Determine hydrodynamic mass of impact per unit area from GE Report NEDE-13426P, Figure 6.8 or 6.9, corresponding to the structure's orientation and width:

(M_H/A), in lbm/ft^2

(3) Determine the impact velocity of the water slug, V, corresponding to the height, H:

$V = (H/10)(2.6-1.6\sqrt{H/10})V_{max}$, in fps, for $0 \leq H \leq 10$ feet

$V = V_{max} = 50$ fps, for $10 \leq H \leq 18$ feet

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(4) Determine design impulse:

$$I_{design} = (M_H/A)(V)\ \frac{1}{4637}\ , \text{ in psi x sec}$$

(5) Determine impulse duration according to G. Maise (1984), Equations 5 or 9, corresponding to structure's orientation, height above pool and length:

t_d, in seconds

(6) Determine the peak dynamic pressure design value:

$$P_{max} = \frac{2I_{design}}{t_d}, \text{ in psi}$$

(7) Determine the dynamic load factor, DLF, corresponding to t_d/T assuming a versed sine shape for the design impulse

(8) Determine equivalent static design pressure:

$$P_{REV} = (P_{max}DLF) \text{ Maise design}$$

(9) The adequacy of original design is dependant on the ratio of pressures, that is:

$$\text{Is } \frac{P_{REV}}{P_{ORIG}} \geq 1.0?$$

where P_{ORIG} is the original equivalent static pressure used for design.

This method was applied to a total of 66 structures for which the values of all of the key parameters listed above were reported in tabular form.

The staff has reviewed this methodology and finds that it conforms in almost all respects to procedural steps previously approved by the NRC staff in NUREG-0487 and NUREG-0661 (essentially the Maise criteria of February 15, 1984). One area of nonconformance has been identified, however. This is the determination of hydrodynamic mass M_H, for circumferentially oriented structures, from Figure 6-9 of GE Report NEDE-13426P. The method approved by the staff requires determination of M_H from Figure 6-8 of NEDE-13426P for all structures.

The modification used by the applicant implies a reduction in the derived load. This reduction is estimated to be about 60% due to the use of Figure 6-9 to determine M_H for circumferentially oriented structures. Application of the staff-approved procedure would, therefore, imply a corresponding increase of the load for circumferential targets.

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Although this is a substantial increase, the staff has found that it is still bounded by the margins demonstrated by the comparisons that were provided by the applicant in all but one case [target No. 3 in Table 2B of the Burns and Roe report (attachment to applicant's letter U-600020 to the staff, May 16, 1985)]. For this particular case, the applicant has reevaluated the design using the increased load estimates and states that the calculated maximum stresses were within the (static) allowable for the material. Accordingly, the staff finds this plant-unique load specification to be acceptable.

6.2.6 Containment Leakage Testing

By letters dated December 9, 1985, and March 11, 1986, the applicant requested two exemptions from certain requirements of Appendix J to 10 CFR 50. The staff's review and conclusions regarding these requests for exemption are given below.

Containment Airlock

Paragraph III.D.2(b)(ii) of Appendix J to 10 CFR 50 requires that airlocks opened during periods when containment integrity is not required by the plant's Technical Specifications shall be tested at the end of such periods at a pressure not less than P_a. In lieu of this requirement, the applicant proposes to substitute the seal leakage test of paragraph III.D.2(b)(iii) of Appendix J for the overall airlock leakage test of paragraph III.D.2(b)(ii) of Appendix J before establishing containment integrity if the airlock has been opened during periods when primary containment integrity is not required.

The existing airlock doors are so designed that a full-pressure test at P_a (9.0 psig) of an entire airlock can only be performed after strongbacks (structural bracing) have been installed on the inner door. This is because the test pressure exerted on the inner doors during the test is in a direction opposite to that of the accident pressure direction. Installing strongbacks, performing the test, and removing the strongbacks, requires several hours per airlock, during which access through the airlock is prohibited.

If the periodic 6-month test required by paragraph III.D.2(b)(i) of Appendix J and the 3-day test required by paragraph III.D.2(b)(iii) of Appendix J are current, no maintenance has been performed on the airlock that could affect its sealing capability, and the airlock is properly sealed, there is no reason to expect the airlock to leak excessively even though it has been opened with the reactor in cold shutdown (mode 4) or refueling (mode 5) condition, when containment integrity is not required. Accordingly, the staff concludes that the applicant's proposed approach of substituting the seal leakage test at P_a of paragraph III.D.2(b)(iii) for the entire airlock test at P_a of paragraph III.D.2(b)(ii) of Appendix J is acceptable when no maintenance has been performed on the airlock that could affect its sealing capability. Therefore, an exemption from the requirements of paragraph III.D.2(b)(ii) of Appendix J is justified and acceptable. Whenever maintenance that could affect its sealing capability has been performed on the airlock, the requirements of paragraph III.D.2(b)(ii) of Appendix J must still be met by the applicant.

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Main Steam Isolation Valves

Appendix J to 10 CFR 50 requires local leak rate testing of boiling-water reactor (BWR) main steam isolation valves (MSIVs) at P_a. the peak calculated containment pressure related to the design-basis accident. Furthermore, paragraph III.C.3 of Appendix J requires that the measured leak rate be included in the summation for the local leak rate tests. The applicant will test the MSIVs at the peak calculated containment pressure for the design-basis accident, but requests an exemption to exclude the measured leakage from the combined local leak rate.

The main steam isolation valve leakage control system (MSIVLCS) is designed to control and minimize the release of fission products that could leak through the closed MSIV after a loss-of-coolant accident (LOCA) by maintaining a negative pressure between the MSIVs. The effluent will be discharged into a volume where it will be processed by the standby gas treatment system (SGTS) before being released to the environs. A radiological assessment for this potential source of containment leakage into the atmosphere was performed on the basis of a leakage rate of 28 standard cubic feet per hour past the inboard MSIVs for each main steam line, which is the staff-approved acceptance limit stated in the SER. The MSIVs will be periodically leak rate tested by the applicant to ensure the validity of the radiological analysis. As described in FSAR Amendment 21, dated December 1982, the applicant modified the MSIVLCS. For each subsystem of the MSIVLCS, the bleed line depressurization branches will discharge to the steam tunnel that is served by the SGTS, and the blower discharge lines will discharge directly to the SGTS for processing. Since the leakage from MSIVs has been accounted for and treated separately in the radiological analysis for the site, the staff concludes that excluding the leakage from the summation for the local leak rate tests is acceptable.

6.2.7 Postaccident Hydrogen Control Requirements

In Section 6.2.7 of the SER, the staff noted that the applicant needed to provide a system to control hydrogen generated from a postulated degraded-core accident. It was reported that the applicant intended to install a hydrogen ignition system (HIS) in the plant for this purpose, based on the Grand Gulf Nuclear Station (Grand Gulf) system design. Also, the applicant planned to submit plant-specific information, including relevant generic information developed by the Mark III Containment Hydrogen Control Owners Group (HCOG) in which the applicant is a participant in support of the Clinton design.

The Nuclear Regulatory Commission (NRC) published an amendment to the hydrogen rule (10 CFR 50.44) on January 25, 1985 (50 FR 3498). This amendment, which affects the Clinton Power Station, became effective on February 25, 1985. The amended rule requires that a hydrogen control system be provided and that the system be capable of accommodating, without losing the integrity of the containment structure, the amount of hydrogen generated from a metal-water reaction involving up to 75% of the active fuel cladding. Since the applicant has elected to install a hydrogen ignition system similar to the system installed at Grand Gulf, the applicant is also required to demonstrate that systems and components necessary to establish and maintain safe shutdown are capable of performing their functions during and after exposure to the environmental conditions created by the burning of hydrogen.

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Pursuant to the provisions of the rule, the applicant has submitted a preliminary analysis of the Clinton system design, and a schedule for meeting the requirements of the rule. This schedule indicates that the final analysis of the Clinton system design is to be based on the generic findings of the Mark III HCOG, supplemented by plant-specific design considerations.

Clinton is one of four plants operating or under construction with a Mark III type of containment and which relies on a hydrogen ignition system as a means of controlling hydrogen during postulated degraded-core accident events. In its evaluation of the HIS for Grand Gulf, the staff concluded, subject to a related license condition, that the ignition system is effective in controlling hydrogen releases from the more likely degraded-core accident scenarios with acceptable consequences. The staff's evaluation is documented in Supplements 3 and 5 to the Grand Gulf Safety Evaluation Report (NUREG-0831). In this supplement to the Clinton SER, the staff provided its evaluation of the preliminary analysis of the HIS for the Clinton Power Station. Although there are geometric configuration similarities between the Grand Gulf and Clinton containment designs, there are dimensional and other differences that are reflected in the analysis. (Table 6.1 compares the Mark III containment characteristics of Grand Gulf, Perry, River Bend, and Clinton.)

A significant part of the remaining work to be accomplished by the HCOG is to determine the effects of hydrogen burning in a continuous fashion such as a diffusion flame extending upwards from the surface of the suppression pool. Since there are no analytical codes available at this time that can be relied on to represent such a mode of hydrogen burning, the HCOG has developed a test program to be carried out in a quarter-scale test facility. Plant-specific configurations for each of the four Mark III plants are to be simulated in these tests. The test results are expected to establish a valid basis for the final analyses required by the rule.

(1) Hydrogen Ignition System

The Clinton hydrogen ignition system is designed to burn hydrogen at low concentrations, preventing the accumulation of high concentrations of hydrogen, which would threaten containment integrity. The HIS is a system of thermal igniters and ancillary equipment. The applicant has indicated that the system will be operable before plant operation exceeds 5% of full reactor power. This complies with the specific requirement of the rule (10 CFR 50.44(c)(3)(vii)(B)).

The igniters are designed to ensure burning of hydrogen in the unlikely event that substantial quantities of hydrogen are generated as a result of a postulated degraded-core accident (involving up to 75% equivalent metal-water reaction, as required by the rule).

The HIS consists of 115 igniter assemblies distributed throughout the drywell structure and the containment vessel. There are 11 igniters in the drywell structure and 104 igniters in the containment vessel that are distributed as follows: 13 igniters in the wetwell region (i.e., below the hydraulic control unit (HCU) floor at plant elevation 755 feet); 64 igniters in the region above the HCU floor and below the refueling floor at plant elevation 828 feet; and the 27 igniters in the upper dome region.

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The igniters are Model 7G glow plugs (commonly used in diesel engines) that are manufactured by General Motors AC Division. The Clinton igniter assembly design is identical to that installed in the Grand Gulf plant. Each igniter is powered directly from a 120/12-V stepdown transformer that has multitap capability. Each igniter assembly consists of a 1/8-inch-thick stainless steel box that contains the transformer and all electrical connections, and is manufactured by the Power Systems Division of Morrison Knudsen. The igniter assemblies are classified as Class 1E and are seismic Category I.

The 115 igniter assemblies are divided into two redundant groups; each group is powered from a separate Class 1E division power supply. There are six circuits in each divisional power supply. The HIS is to be manually activated from the reactor control room in accordance with emergency operating procedures.

The Clinton HIS is designed to promote the burning of hydrogen at lean concentrations and in a reliable manner. At least two igniters are located in each enclosed volume or area within the containment that are subject to possible hydrogen pocketing; each of the two igniters is powered from a separate power division. In open areas within the containment and drywell regions, igniter assemblies at the same elevation are alternated with respect to their Class 1E division power source.

The applicant has implemented preoperational and surveillance testing programs similar to the programs established and approved by the staff for Grand Gulf. These programs ensure the operability and functionability of the HIS, verifying the proper functioning of the controls, wiring, instrumentation, and critical components, along with adequacy of the operating igniters' surface temperature.

On the basis of its review of the design information provided, the staff finds that the design arrangement described above ensures that hydrogen will burn reliably and effectively and has an acceptable number and distribution of potential ignition points. Therefore, the staff concludes that the Clinton HIS is acceptable, subject to resolution of certain issues that are to be addressed in the applicant's final analysis, as provided for in the rule, and discussed in the sections that follow.

(2) Structural Capacity

The details of the staff's evaluation regarding the containment and drywell ultimate capacities are documented in Supplements 1 and 4 to the Clinton SER. In summary, the positive and negative containment pressure capacities were determined to be 63 psig and -11 psig, respectively. The drywell negative pressure capacity was determined to be -61 psig.

(3) Hydrogen Generation for Postulated Degraded-Core Accidents

This section addresses the suitability of hydrogen generation rates employed by the applicant in the preliminary analysis of the Clinton containment pressure and temperature response to hydrogen combustion.

(a) Sequences Analyzed

The applicant has analyzed two degraded-core accident sequences. The first is a transient with an initial loss of all makeup water sources and

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a concurrent stuck-open relief valve (SORV) and subsequent recovery of an injection source greater than or equal to 5000 gallons per minute (gpm) after a substantial time delay following reactor trip. The staff notes that this event is a surrogate for all transients with loss of makeup water. The SORV leads to faster core uncovery (three-fourths uncovered at about 40 minutes following reactor trip) than a transient with operable cycling relief valves (three-fourths uncovered at about an hour following reactor trip). The SORV case is somewhat more conservative than the transient with cycling relief valves since the decay heat is somewhat higher at the earlier uncovery. The second sequence is a small break loss-of-coolant inside the drywell (drywell break, DWB) with concurrent loss of all makeup water sources.

(b) Hydrogen Generation

The hydrogen and steam release rates were derived from the boiling-water reactor (BWR) core HEATUP code calculations. In the DWB case, the hydrogen and steam flow split was determined by a mechanistic calculation using the MAAP code until core recovery. The staff and its consultants have performed extensive comparisons of independent calculations of (1) an unmitigated case (i.e., no injection of makeup water during the hydrogen generation event), (2) no injection for some period of time followed by makeup flows from an ESF source, and (3) no injection for some period of time followed by injection at 150 gpm and 300 gpm, respectively. Comparisons between the BWR core HEATUP code and independent calculations of the SORV transient sequence for cases 1 and 2 showed good agreement and provide the basis for preliminary acceptance of hydrogen generation predictions for Clinton. On the other hand, the staff has not performed the same indepth comparison to MAAP calculations and makes no finding at this time with regard to the acceptability of these calculations for the DWB accident sequence. However, because the DWB sequence is considerably less probable than the SORV transient sequence, the staff has determined that there is no undue risk involved in deferring this consideration of the DWB sequence to the final analysis. Case 3 will be addressed in the applicant's final analysis.

For an event involving loss of all makeup water, irrespective of whether the event is SORV transient or DWB, the Emergency Procedure Guidelines specify a manual depressurization of the reactor vessel by means of the automatic depressurization system (ADS) when the vessel's water level has decreased to the point at which about three-quarters of the core is uncovered. The applicant conservatively assumes this occurs at 2000 seconds. Following the ADS actuation, without any makeup flow, the core would become uncovered and begin to overheat, causing Zircaloy reaction with passing steam and producing hydrogen and zirconium dioxide. The emergency core cooling system (ECCS) is then assumed to be recovered at 3870 seconds, resulting in a 5000 gpm reflood in the vessel. Once reflood is initiated, the vessel water level rises rapidly and begins to quench the overheated core. This produces large quantities of steam and causes a spike in the hydrogen generation. These aspects of hydrogen generation have been reasonably modeled by the applicant.

The amended hydrogen rule requires that the hydrogen control system handle the hydrogen produced by oxidation of up to 75% of the equivalent

active cladding. Both the BWR core HEATUP code as used in the applicant's calculations and in independent staff calculations have indicated that such a high degree of oxidation is improbable in a core geometry so intact that the core remains amenable to cooling. The applicant has referenced Hydrogen Control Owners Group (HCOG) work (HGN-034) which is based on a quasi-static debris bed coolability model with a constant hydrogen release rate of 0.1 lb_m/sec until a cumulative release equivalent to the oxidation of 75% of the cladding in the active core region is reached. The staff accepts the stipulated hydrogen release rate of 0.1 lb_m/sec for use in the preliminary containment analysis. Independent staff calculations of a cyclical core uncovery, heatup, and quenching have shown a similar average rate over several cycles.

(4) Containment Response Analysis

The applicant has provided a preliminary analysis to support interim operation at full power until the final analysis is completed. Using the hydrogen and steam releases obtained from the BWR core HEATUP code (see section above on hydrogen generation for degraded-core accidents), the applicant calculated the containment atmosphere transient using the CLASIX-3 code. The CLASIX-3 code is a multi-volume containment code that is used to calculate the containment pressure and temperature response in the separate compartments. This code has the capability to model features that are unique to Mark III containments while tracking the distribution of the atmosphere constituents (i.e., oxygen, nitrogen, hydrogen, steam). It should be noted that CLASIX-3 models deflagration (discrete-type) burning in the containment; diffusion-type (continuous) burning will be addressed in the applicant's final analysis on the basis of results of the quarter-scale test program as noted earlier.

The applicant considered two types of accidents in its preliminary analysis of the HIS: a stuck-open relief valve (SORV) transient and a small-break loss-of-coolant accident (LOCA) in the drywell. The BWR core HEATUP code steam and hydrogen releases are fed into the CLASIX-3 code. For the SORV case, all the mass and energy releases are directed into the suppression pool. For the drywell break case, the mass and energy releases are directed in the drywell and into the suppression pool as determined by the MAAP code.

The CLASIX-3 model used in this analysis simulates four compartments of the Clinton Power Station: the drywell volume, the wetwell volume (bounded by the HCU floor and the top of the suppression pool), the intermediate volume (bounded by the HCU floor and the refueling floor), and the containment volume (above the refueling floor). Operation of only one of the two containment sprays was assumed. With regard to hydrogen combustion, ignition was calculated to occur at an 8% hydrogen concentration with 85% combustion completeness; propagation of burning into other compartments also was assumed to occur at 8% hydrogen concentration with a flame speed of 6 feet per second. The Clinton SORV base case produces a transient in which the hydrogen is ignited in a series of burns in the wetwell volume. The CLASIX-3 code predicts a sequence of 41 wetwell burns (approximately 37 pounds of consumed hydrogen per burn). Figures 6.2 and 6.3 show the wetwell temperature and pressure profiles. The first burn resulted in the highest estimated wetwell temperature (1221°F) for the entire transient, because the containment sprays are not activated until after the first burn. The remaining wetwell burns produce a peak wetwell temperature of about 1050°F.

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At the end of the hydrogen release period, the hydrogen concentration in the containment volume does not reach the ignition setpoint of 8%; the average concentration of hydrogen in the containment volume is about 6.5%. The applicant forced the only containment burn at the lower concentration in the evaluation, and this resulted in the most severe pressure excursion to approximately 23 psig.

For the base case analysis of a small pipe break in the drywell, the CLASIX-3 containment model used is similar to the SORV case except for the hydrogen/steam source terms. The results of the drywell break CLASIX-3 analysis produces a similar wetwell temperature profile (36 burns) as compared with the SORV case (41 burns). Also, at the end of the hydrogen release period, the hydrogen concentration in the containment volume does not reach the ignition setpoint of 8%; the concentration of hydrogen in the containment volume is estimated at about 7.5%. The applicant induced the only hydrogen burn in the containment volume at the lower concentration and this resulted in the most severe estimated pressure excursion (to approximately 35 psig).

In reviewing the overall CLASIX-3 code containment modeling used in the preliminary analysis, certain assumptions need to be justified. The applicant will address these concerns in the final analysis and will submit justification to the staff for review. If the final containment environmental profiles are found to be more severe than the present analysis, the applicant committed to confirm equipment survivability with the modified profiles, or initiate appropriate equipment modifications as necessary. The staff concludes that the applicant's preliminary analysis of the containment constitutes a reasonable methodology for demonstrating the performance of the HIS on the basis of the above findings.

Testing of Wetwell Thermal Environment

In the Grand Gulf SSER 5, the staff described some of the results of an earlier twentieth-scale HCOG test program. The objective of the twentieth-scale test was to provide a visual record of hydrogen combustion behavior in a Mark III containment enclosure. A principal finding was that when hydrogen flow rates of 0.4 lb/sec or greater are injected in the suppression pool, continuous burning of hydrogen in the form of a steady diffusion flame occurred above the suppression pool. However, the test facility was inadequate to permit scaleup of the thermal environment to an actual Mark III wetwell volume. Therefore, HCOG proposed a quarter-scale research test facility, and this is also described in the Grand Gulf SSER 5.

Preliminary results from the quarter-scale scoping tests reveal that the diffusion flame threshold is significantly lower, about 0.14 lb/sec, and steady flames can exist as low as 0.035 lb/sec under certain background conditions. In these initial tests, the only deflagration burns observed have been the initial "lightoff" before the formation of diffusion flames. Also, the bulk hydrogen concentration was maintained below 5%, thus demonstrating effective performance of the igniters to burn at lean hydrogen mixtures. These results have a significant bearing on the extent to which the CLASIX-3 code can be relied upon to predict containment temperature environments, and further emphasizes the importance of the test program.

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(5) Equipment Survivability

By letters dated November 4, 1985, and February 21, 1986, the applicant submitted an evaluation of survivability of the essential equipment exposed to the thermal environment postulated in the containment during hydrogen burn initiated by the hydrogen ignition system (HIS). Although this system was designed to prevent high hydrogen concentration buildup by deliberate ignition of relatively low concentrations of hydrogen air-steam mixtures, the resulting release of thermal energy may still be sufficient to significantly increase the temperature of the equipment located in the containment. Since some of this equipment is needed to ensure safe shutdown and containment integrity, the applicant was required to demonstrate that the essential equipment located inside the containment will survive the hydrogen burn environment resulting from operation of the HIS.

In the preliminary analysis, the applicant has determined the thermal response of the hydrogen igniter assembly exposed to a hydrogen deflagration burn environment, and has demonstrated that the resulting temperatures and pressures did not exceed the qualification limits. The applicant was also able to demonstrate that because of the similarity between the equipment in the Grand Gulf Nuclear Station and in Clinton Power Station, most of survivability analyses performed for Grand Gulf were applicable to Clinton.

Safety-Related Equipment

The selection of the equipment which has to survive hydrogen burning was based on its functions during and after an accident. In general, all the equipment located in the containment which was included in the following four categories of systems was considered to be essential for safety of the plant:

(1) systems mitigating the consequences of the accident

(2) systems needed for maintaining integrity of the containment pressure boundary

(3) systems needed for maintaining the core in a safe condition

(4) systems needed for monitoring the course of the accident

Using these criteria in its submittal of November 4, 1985, the applicant listed the equipment whose survivability needed to be evaluated. This list contained the following categories of equipment:

(1) containment structure, penetration, locks, and hatches
(2) hydrogen control system
(3) combustible gas control system
(4) emergency core cooling systems (HPCS, LPCS, LPCI, ADS)
(5) RHR containment spray
(6) containment and reactor monitoring instrumentation
(7) associated instruments, controls, and cable

The staff has reviewed the applicant's criteria for selecting the essential equipment and has determined that the criteria should be modified to also include equipment whose failure could adversely affect the function of essential

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equipment required for the hydrogen burn event, or that could mislead the operator, and the equipment required by the EPGs. The applicant should resolve this item in the final analysis through the HCOG program. The staff's view is that these new criteria will not result in additional equipment being identified or, if so, will not identify any new equipment type for which equipment operability has not been demonstrated. Therefore, on these bases, the staff finds the essential equipment list for Clinton is acceptable for the preliminary analysis.

Thermal Environment

The thermal environment for the preliminary evaluation of equipment survivability at Clinton was determined by the CLASIX-3 computer code (see section above on containment response analysis). These analytical assumptions were identical to those in the Grand Gulf equipment survivability analysis. The thermal environment corresponding to the SORV was slightly more severe and it was used for the equipment survival analyses. There are some differences between the SORV temperature profiles in Clinton and Grand Gulf. In Clinton, the average peak temperature is higher but the number of burns is lower and, hence, the time intervals between the burns are longer. Also, in Clinton, the spray flow rate is lower compared to Grand Gulf. Hence, the thermal energy transferred to the equipment in Clinton exceeds the energy in Grand Gulf. The applicant has provided additional justification to demonstrate that the Grand Gulf analysis can still be used to demonstrate equipment survivability for Clinton. This justification is discussed below.

Thermal Response Analyses

The thermal response analyses of the equipment was determined on the basis of a comparison with the Grand Gulf equipment. The applicant also performed an analysis on a similar component (the hydrogen igniter) using the HEATING computer code. A later version, HEATING-6, was used for Clinton instead of the HEATING-3 version used for Grand Gulf. The heat transfer methodology and equations are essentially the same in the two versions. The difference is modifications in HEATING-6 which improves the efficiency of the code. The applicant has demonstrated that although the maximum temperature reached by the igniter is slightly higher for the Clinton thermal environment, compared to the maximum temperature reached in Grand Gulf thermal environment, it is still lower than the qualification temperature for this component. The difference in thermal response is due to somewhat different assumptions made in the Clinton and Grand Gulf analyses.

On the basis of this analysis, the final igniter surface temperature predicted for Clinton is 295°F, which is 49°F higher than the Grand Gulf final surface temperature of 246°F. Hence, the applicant has added this 49°F to all calculated surface temperatures for Grand Gulf to predict the surface temperature of Clinton equipment. Although the hydrogen igniter may not be the most heat-sensitive component, the staff is of the opinion that on the basis of many conservative assumptions used in the analysis, this approach conservatively predicts the equipment thermal response for the Clinton plant.

Survivability of Essential Equipment

The acceptance criterion used for evaluating survivability of essential equipment is based on its qualification temperature and how long the temperature is

maintained. The equipment located in the containment will survive a hydrogen burn if the temperature reached by its most sensitive component will not exceed the temperature reached by this component during qualification tests. Because the actual temperature reached by the tested equipment during these tests was not measured and the qualification temperature was the temperature of the environment to which the tested equipment was exposed, there is no direct way to determine the actual qualification temperature reached by the limiting components. However, environmental qualification tests are typically conducted for extended periods of time and the surface temperature should achieve equilibrium with the test chamber temperature during the tests. Therefore, the temperature of the test environment could be used as a close approximation of the temperature reached by the sensitive components. The staff finds this assumption acceptable. Because of several conservative assumptions in the thermal response analysis, the staff is of the opinion that evaluating the survivability of limiting components is acceptable for the interim. However, the applicant should identify all equipment by plant identification numbers and submit, with the final analysis of the hydrogen control issue, the respective qualification system component evaluation worksheet (SCEW) so that the staff can verify the applicant's claim regarding the equipment temperature response.

In order to evaluate the survivability of the limiting equipment, in submittals dated November 4, 1985, and February 21, 1986, the applicant compared the qualification temperatures for all essential components at Clinton and Grand Gulf. In all cases, the Clinton qualification temperature was equal to or higher than the Grand Gulf qualification temperature.

In its February 21, 1986, submittal, the applicant, after adding 49°F (the temperature difference between the calculated igniter surface temperature for Grand Gulf and Clinton) to the calculated surface temperature for other Grand Gulf equipment, compared this temperature to the qualification temperature. This comparison indicated that in all cases, except for instrumentation cables and electrical penetration cables, the equipment qualification temperature exceeds the predicted surface temperature for Clinton. For the instrumentation cables and electrical penetration cables, the predicted surface temperature exceeds the qualification temperature by only 3°F. However, the interior temperature at the insulation surface will be lower than the qualification temperature.

It should be noted that computer codes, in general, involve the use of simplifying assumptions to mathematically represent complex physical phenomena. In particular, the CLASIX-3 code may not realistically model the hydrogen burn phenomena in a Mark III wetwell. This conclusion is based on the preliminary results of the 1/4-scale test program. Moreover, the HCOG program plan contains provisions for evaluating potential physical modifications to its respective equipment to ensure equipment survivability if this should be necessary. On the basis of this conclusion, it is the staff's judgment that the applicant has provided sufficient information to demonstrate equipment survivability for the preliminary analysis.

Although in this analysis the applicant used a containment temperature profile which would be conservative relative to all profiles that may result from credible accidents, there is a location in the containment above the suppression pool where, under certain circumstances, the equipment could be exposed to a diffusion flame environment produced by a continuous burn of hydrogen released from the suppression pool. However, the staff is of the opinion that

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the effect of this source of thermal energy on equipment thermal response is significantly minimized by the shielding provided by different structural components. The applicant should, however, address this problem in the final analysis when the results of the HCOG test dealing with this phenomenon become available.

Pressure Effects on Essential Equipment

The applicant has performed a preliminary evaluation of the effect of pressure on the survival of essential equipment. This preliminary evaluation indicated that the qualification and/or design pressures bound the calculated pressures the equipment could experience during hydrogen combustion. The staff has reviewed the applicant's evaluation and finds that there is reasonable assurance that the essential equipment will survive the pressures generated during a hydrogen burn.

Conclusions

The preliminary analysis performed by the applicant provides a satisfactory basis to support interim operation at full reactor power until the final analysis has been completed. There is reasonable assurance that the Clinton hydrogen ignition system will act to control the burning of hydrogen so that there is adequate protection against containment failure. On the basis of the preliminary analysis performed by the applicant, the staff finds that the peak pressures as a result of igniter-induced burns will be less than the containment pressure capacity (63 psig).

As a result of that preliminary analysis, there are residual staff concerns that need to be resolved in the final analysis. The applicant has indicated that it will rely on the ongoing experimental and analytical program, as set forth by the HCOG, to resolve the staff's remaining concerns in a manner that is expected to resolve them for the Clinton plant. The following are the key staff concerns that the applicant has committed to address in the final analysis of the hydrogen control system design for Clinton:

(1) hydrogen-steam release histories that are representative of the degraded core accident sequences chosen by the applicant

(2) containment diffusion flame environment with reliance on data from the quarter-scale test facility

(3) containment environmental analysis as related to deflagration-type burning; e.g., effects on transients when considering spray carryover estimates

(4) drywell environmental analysis, deflagration combustion, and the assessment of possible inverted diffusion flames

(5) confirmation of equipment survivability determined from the preliminary analysis discussed above, using modified thermal profiles as applicable and

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(6) development of combustible gas control emergency procedures guidelines

The staff will continue to work with the applicant through the HCOG and will report its findings following receipt and assessment of the final analysis to be submitted by the applicant at the conclusion of the HCOG program.

The staff concludes that the applicant satisfactorily meets the requirements of 10 CFR 50.44, applicable at this stage, for operation in excess of 5% of rated power. In view of the enactment of the amended hydrogen rule and based on the staff's evaluation and conclusions discussed above, the proposed SER license condition 5, as listed in Section 1.11 of the SER, is no longer needed and is being deleted by this supplement.

On June 25, 1985, the applicant submitted a proposed schedule for meeting the requirements of the final rule on hydrogen control as required by 10 CFR 50.44(3)(c)(vii)(A). The proposed schedule is based on the current schedule for completion of all tasks incorporated in the Mark III Containment Hydrogen Control Owners Group (HCOG) Program Plan (Revision 3). The Program Plan identifies December 31, 1986, as the scheduled date for completing and submitting to the staff all elements of the final analysis required by the rule. However, recent discussions with HCOG has revealed a revised schedule for completing the final analysis to be mid-1987. This date is acceptable to the staff for completion of the final analysis. In the event that the final analysis should provide a basis for the staff to conclude that equipment enhancements are necessary to ensure survivability of certain essential equipment during the postulated hydrogen burn events, as required by the rule, an additional period of time will be needed to implement such enhancements. Any enhancements determined to be necessary shall be implemented before startup following the first refueling outage as discussed by the applicant in its June 25, 1985, letter.

6.3 Emergency Core Cooling System

6.3.1 System Description

By letter dated May 27, 1986, the applicant requested changes to the Clinton Power Station Technical Specification Table 4.3.3.1-1. These changes involve deleting the requirement for operability of the high-pressure core spray (HPCS) system during reactor startup (below 600 psig) because reactor wide-range water-level instrumentation is not calibrated for startup conditions.

The Clinton reactor pressure vessel (RPV) Level 8 wide-range instrumentation is calibrated for rated reactor operating temperature and pressure. At lower temperatures and pressures (as during startup of the plant), the wide-range instrumentation will read higher than actual because of increased water density in the RPV; the error is estimated to be about 39 inches. With this amount of error, the HPCS system isolation setpoint will be reached and the HPCS system will be locked out and must, therefore, be declared inoperable.

This inoperability of the HPCS system when the reactor pressure is below about 600 psig during startup is not judged to be a significant safety problem because of the following considerations:

During startup at less than 600 psig, the reactor power level would be less than 2% of rated power with a peak linear heat generation rate of less than 1.0 kW/ft.

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At this power level, the core would heat up very slowly from decay heat if it were to uncover following a LOCA. Further, the HPCS isolation will clear automatically and the system will start automatically when Level 2 is indicated. Since the magnitude of the level error is proportional to the actual height of water above the level tap, the error will decrease as actual water level decreases. The level error when Level 2 is indicated will, therefore, be less than 39 inches and HPCS would start at an actual level which is more than 6 feet above the top of the active fuel. In addition, none of the other emergency core cooling systems are affected by this calibration consideration and are all required to be operable before startup procedures are initiated. The consequences of an event which occurs during the startup conditions stated above will, therefore, be bounded by design-basis-accident analysis results.

The staff has concluded that the proposed Clinton Technical Specification changes in Table 4.3.3.1-1 requested by the applicant are acceptable.

6.6 Inservice Inspection of Class 2 and 3 Components

6.6.1 Evaluation of Compliance With 10 CFR 50.55a(g) for Clinton Unit 1

This evaluation supplements conclusions in the corresponding section and Appendix I of Supplement 5 to this SER which address the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g).

In a submittal dated October 8, 1985, the applicant requested relief from ASME Code Section XI requirements which were determined to be not practical to perform. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). The staff's evaluation of these relief requests was reported in Appendix I of Supplement 5 to the SER.

In a letter dated March 17, 1986, the applicant requested relief from an additional Code requirement and provided a supporting technical justification. The staff, with technical assistance of Department of Energy (DOE) contractors from Idaho National Engineering Laboratory (INEL), has reviewed this submittal to determine if relief from the Code requirement was justified. Pursuant to 10 CFR 50.55a(a)(3), relief from the Code requirement has been allowed for those requirements that, if implemented, would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The evaluation of the additional relief request, which was prepared by the staff and its contractor, is contained in Appendix I to this supplement to the SER. On the basis of granting relief from this preservice examination requirement, the staff concludes that the Preservice Inspection Program for Unit 1 is in compliance with 10 CFR 50.55a(g)(2).

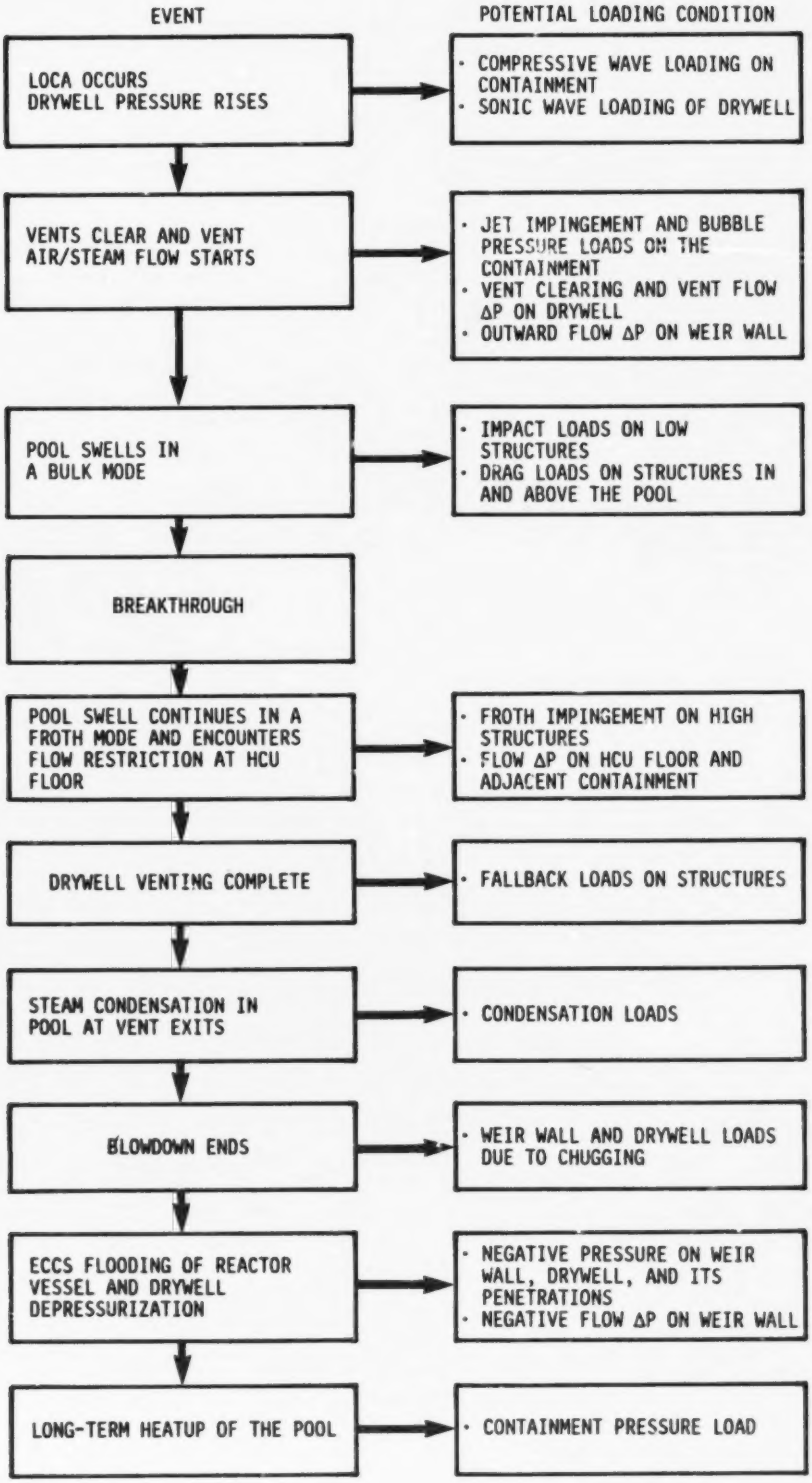
EVENT
POTENTIAL LOADING CONDITION
LOCA OCCURS
DRYWELL PRESSURE RISES
· COMPRESSIVE WAVE LOADING ON CONTAINMENT
· SONIC WAVE LOADING OF DRYWELL
VENTS CLEAR AND VENT AIR/STEAM FLOW STARTS
· JET IMPINGEMENT AND BUBBLE PRESSURE LOADS ON THE CONTAINMENT
· VENT CLEARING AND VENT FLOW ΔP ON DRYWELL
· OUTWARD FLOW ΔP ON WEIR WALL
POOL SWELLS IN A BULK MODE
· IMPACT LOADS ON LOW STRUCTURES
· DRAG LOADS ON STRUCTURES IN AND ABOVE THE POOL
BREAKTHROUGH
POOL SWELL CONTINUES IN A FROTH MODE AND ENCOUNTERS FLOW RESTRICTION AT HCU FLOOR
· FROTH IMPINGEMENT ON HIGH STRUCTURES
· FLOW ΔP ON HCU FLOOR AND ADJACENT CONTAINMENT
DRYWELL VENTING COMPLETE
· FALLBACK LOADS ON STRUCTURES
STEAM CONDENSATION IN POOL AT VENT EXITS
· CONDENSATION LOADS
BLOWDOWN ENDS
· WEIR WALL AND DRYWELL LOADS DUE TO CHUGGING
ECCS FLOODING OF REACTOR VESSEL AND DRYWELL DEPRESSURIZATION
· NEGATIVE PRESSURE ON WEIR WALL, DRYWELL, AND ITS PENETRATIONS
· NEGATIVE FLOW ΔP ON WEIR WALL
LONG-TERM HEATUP OF THE POOL
· CONTAINMENT PRESSURE LOAD

Figure 6.1 Loss-of-coolant accident chronology (design-basis accident)

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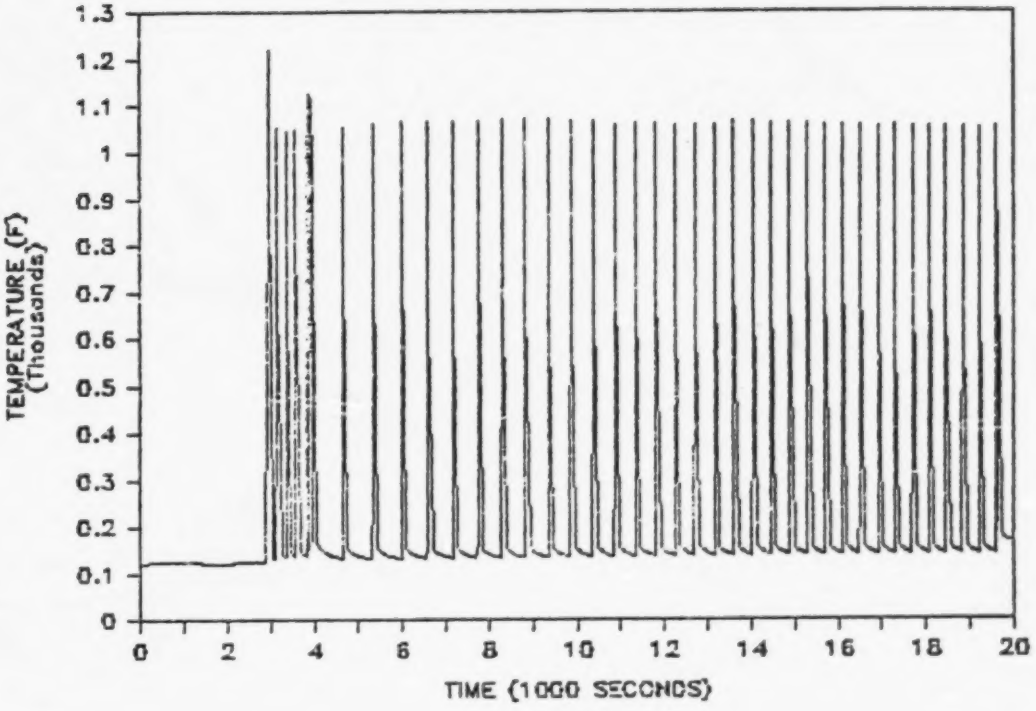

Figure 6.2 Illinois Power Co./Clinton SORV, 5000 gpm reflood wetwell temperature vs. time

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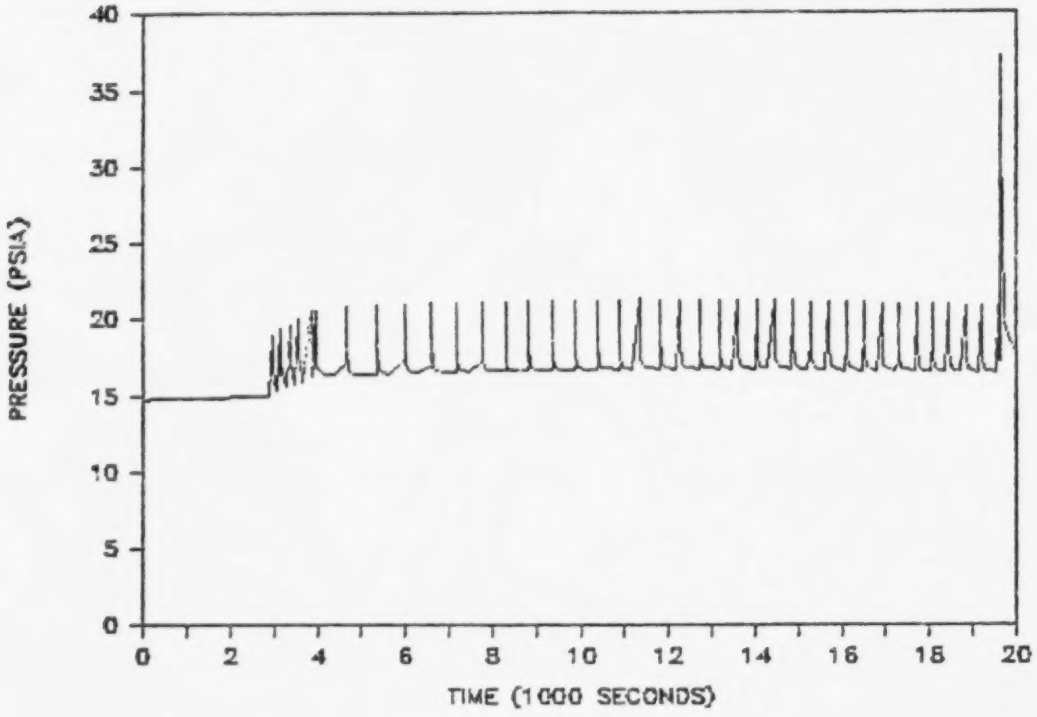

Figure 6.3 Illinois Power Co./Clinton SORV, 5000 gpm reflood wetwell pressure vs. time

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Table 6.1 Comparison of BWR Mark III containment characteristics

Characteristic and unit of measure	Grand Gulf	Perry	River Bend	Clinton
Rated thermal output, MWt	3,833	3,579	2,894	2,894
Number of fuel bundles	800	748	624	624
Drywell structure				
Design pressure, psig	30	30	25	30
External design pressure, psid	21	21	20	17
Air volume, ft^3	270,000	277,685	236,196	246,500
Suppression pool volume (includes vents), ft^3	1.3E4	1.12E4	1.3E4	1.1E4
Suppression pool surface area, ft^2	553	482	522	455
Holdup volume, ft^3	50,000	40,564	20,353	33,804
Holdup surface area, ft^2	3,145	2,617	2,564	2,490
Containment vessel				
Design pressure, psig	15	15	15	15
Ultimate pressure capacity, psig	56	50	53	63
External design pressure, psid	3	0.8	0.6	3
Total air volume, ft^3	1.4E6	1.141E6	1.192E6	1.551E6
Air volume below hydraulic control unit floor, ft^3	151,644	181,626	153,792	173,000
Suppression pool volume, ft^3	1.24E5	1.06E5	1.28E5	1.35E5
Suppression pool surface area, ft^2	6,667	5,900	6,408	7,175
Upper pool makeup volume, ft^3	36,380	32,830	0	14,655
Containment spray flow rate (1 train), gpm	5,650	5,250	0	3,800
Number of loss-of-coolant-accident vents	135	120	129	102

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7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Protector System

7.2.3 Resolution of Issues

7.2.3.1 Recirculation Pump Trip

Chapter 7 of the Clinton FSAR has been revised to include a description of the anticipated transient without scram recirculation pump trip (ATWS RPT) design. The Clinton design consists of two independent trip logics, one per recirculation pump. Each logic consists of two reactor vessel, low-water-level channels arranged in a two-out-of-two energize-to-actuate configuration in parallel with two reactor vessel high-pressure channels also arranged in a two-out-of-two energize-to-actuate configuration. The ATWS RPT sensors, logic, and pump breaker control circuits are powered from non-Class 1E, 125-V dc power supplies that are independent from the power supplies used in the existing reactor protection system. A trip signal from either logic will actuate breakers that interrupt power from both 6.9-kV normal supply bus and the low-frequency motor generator set for the associated recirculation pump. The components used are electrically independent from the reactor protection system equipment. The equipment is qualified for anticipated operational occurrences. The design includes a bypass capability which allows testing at power, as well as maintenance and calibration functions. The bypass condition, individual channel trip conditions, channel inoperable conditions, and an RPT condition are annunciated in the control room. Following a trip, manual reset is required before pump restart. The potential for inadvertent actuation is minimized through the use of two-out-of-two energize-to-actuate logic. The Clinton Technical Specifications include surveillance requirements for periodically verifying the operability of the ATWS RPT system instrumentation, including bypass circuits, for each recirculation pump.

On the basis of its review, the staff finds the Clinton ATWS RPT design acceptable, and concludes that the design adequately meets the requirements of 10 CFR 50.62 paragraph (5).

7.2.3.3 Self-Test System (STS)

The self-test system is a testing and surveillance system designed to automatically and continuously monitor the nuclear system protection system (NSPS) functional circuitry at Clinton. The NSPS consists of four independent and redundant divisions of safety-related solid-state circuitry used to scram the reactor and to initiate engineered safety features systems. The NSPS is made up of the following systems, all of which are tested by the STS: reactor protection system, nuclear steam supply shutoff system, automatic depressurization system, high-pressure core-spray system, low-pressure core spray system, residual heat removal system, and reactor core isolation cooling system. The staff has approved the STS for performing surveillance testing required by the Clinton plant Technical Specifications. The STS is described in detail in Supplement No. 2 of the Clinton SER, Section 7.2.3.3. The specific tests performed

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or augmented by the STS, means for testing NSPS circuits not monitored by the STS, and the Technical Specification operability requirements for the STS itself are discussed below.

The STS is defined in the Clinton Technical Specifications as follows:

> THE SELF TEST SYSTEM (STS) shall be that automatic test system designed to continually monitor the solid-state nuclear system protection system (NSPS) functional circuitry by injecting short-duration pulses into circuits and verifying proper circuit response to various input combinations. The SELF TEST SYSTEM is designed to maintain surveillance over all NSPS cabinet circuitry essential to the Reactor Protection System, Emergency Core Cooling Systems, Reactor Core Isolation Cooling System, and the Nuclear Steam Supply Shutoff System on a continuous cyclic basis.
>
> The SELF TEST SYSTEM may be used to perform various surveillance testing functions to satisfy Technical Specification requirements for those components it is designed to monitor. The STS may be used to augment conventional testing methods to perform CHANNEL CHECKS, CHANNEL FUNCTIONAL TESTS, CHANNEL CALIBRATIONS, RESPONSE TIME TESTS, and LOGIC SYSTEM FUNCTIONAL TESTS provided that OPERABILITY of the STS has first been verified.

Section 3/4.3.10 (Nuclear System Protection System - Self Test System) of the Clinton Technical Specifications requires the STS to be operable and to be operating in the fully automatic mode during all operational conditions from power operations to and including refueling. Each of the four divisional NSPS control room panels contains a self-test controller (STC) consisting of a microprocessor executing firmware program designed to perform the NSPS circuit monitoring function of the STS. Because the STCs are also used to augment required Technical Specification surveillance, the STS NSPS monitoring function is interrupted when performing this surveillance. Therefore, the Technical Specifications allow for the STS to be periodically taken out of the fully automatic mode of operation for up to 2 hours for the purpose of performing required Technical Specification surveillance of NSPS circuitry. Following completion of surveillance activities, the STS is manually returned to the fully automatic mode of operation. The Technical Specification limiting condition for operation (LCO) for the STS states that if the STS is not operable and operating in the fully automatic mode, the STS must be restored to fully automatic operation within 30 days, or the reactor is required to be placed in at least the hot shutdown condition within the next 12 hours, and subsequently in the cold shutdown condition within the following 24 hours. Thus, the NSPS functional circuitry may go untested with the STS inoperable for up to a month. This interval is consistent with the Technical Specification required surveillance frequency for channel functional tests (CFTs). All other NSPS required surveillance is performed less frequently than CFTs, with the exception of CHANNEL CHECKS (typically performed once per shift) which can be performed independent of the STS. The staff concludes that the Technical Specification operability requirements and LCO for the STS are acceptable.

Each STC tests the NSPS circuitry within its cabinet (from analog trip module input through load driver) and verifies proper inputs from the remaining three NSPS cabinets. Each STC in turn becomes the master test unit, with the other three STC units acting as slaves responding to commands from the master unit.

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It takes an STC (acting as the master unit) roughly 15 minutes to perform its testing function before passing control on to the next STC (to act as the master unit). Thus, all NSPS divisions are tested in roughly 1 hour.

Before a given STC begins its test sequence on the safety circuitry, it first tests itself to verify that it is functioning properly. This is done in two phases. The first phase tests the central processing unit (CPU) function, read-only memory (ROM), random access memory (RAM), and hardware counter/timer circuits. The second phase tests the universal input/output (I/O) ports and all other STC interface circuitry. If a problem is detected during the STC test on itself, the test is halted and annunciation is provided in the control room. If the STC (which has just become the master unit) does not successfully complete its self-check, the STC that has just completed its tests (i.e., the retiring master unit) will annunciate this fact. Thus during the self-check phase of a given STC, another STC is monitoring the process (in particular, an STC whose operability has just been validated and that has successfully tested its own division). In addition, the operators will obtain status indications of the STS at least once every 24 hours in accordance with Technical Specification requirements whenever the STS is operating in the fully or partially automatic mode. These status indications are provided in a summary status matrix when the "NSPS Program" is requested via terminal keyboards in the computer room or at the NSPS panels. The information displayed includes whether all four STCs are in the automatic mode, which STC is acting as master and which STCs are slaves, and whether any fault conditions have been detected. The summary display is followed by an error log for each division. The staff concludes that the combination of STC automatic self-tests and periodic (daily) manual STS status checks are sufficient to verify STS operability.

The role of the STS in performing required Technical Specification surveillance is discussed below.

A channel check is defined as the qualitative assessment of channel behavior during operation by observation. This assessment is to include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter. The STS includes a "monitor/compare" function that displays all four transmitter outputs for comparison. This display function can be used regardless of whether or not the STS is operable (i.e., performing its monitoring function). However, this form of channel check does not verify operability of the vertical indicators on the main control boards [e.g., the ECCS (emergency core cooling system) benchboard] or the Nuclenet CRT displays. The applicant has stated that the Clinton procedures for channel checks include provisions to verify the operability of vertical indicators, CRT displays, and analog trip module (ATM) displays. Channel checks for NSPS instrument channels are performed each shift.

A channel functional test (CFT) is defined for analog channels as the injection of a simulated signal into the channel as close to the sensor as practicable to verify operability, including alarm and/or trip functions and channel failure trips; and for bistable (digital) channels as the injection of a simulated signal into the sensor to verify operability including alarm and/or trip functions. The channel functional test may be performed by any series of sequential, overlapping or total channel steps so that the entire channel is tested. The STS will be used to verify that the ATMs are operable (i.e., will trip on an increasing or decreasing trip signal - whichever applies) but will not determine

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the exact trip setpoint as is done during channel calibrations, discussed below. CFTs can be performed independent of the STS. The CFTs performed by the STS are too fast to activate the associated control room annunciator points and computer printout. Therefore, the Clinton procedures for CFTs include provisions to independently verify the operability of the annunciators and the computer printouts/alarms. CFTs for NSPS instrument channels are performed monthly.

A channel calibration is defined as the adjustment, as necessary, of the channel output so that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. The channel calibration encompasses the entire channel including the sensor and alarm and/or trip functions, and includes the channel functional test. The channel calibration may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is calibrated. Channel calibrations are performed monthly to determine ATM trip setpoints, and at 18-month intervals for other instrument channel components. The STS contains circuitry that ramps a current signal (0-50 ma) into the ATM inputs and displays the exact value at which the ATM trip occurs. Channel calibrations can be performed independently of the STS.

A logic system functional test (LSFT) is defined as a test of all logic components, i.e., all relays and contacts, all trip units, solid-state logic elements, etc., of a logic circuit from sensor through and including the actuated device to verify operability. The logic system functional test may be performed by any series of sequential, overlapping, or total system steps so that the entire logic system is tested. LSFTs are performed once every 18 months. The NSPS functional logic is continually automatically tested by the STS during reactor operation, but cannot be tested independent of the STS during operation. Therefore, the Clinton Technical Specifications require that portions of the NSPS logic are manually tested during each refueling outage independent of the STS, so that all NSPS trip/actuation functions are tested independently of the STS at least once every four fuel cycles. The purpose of these tests is to provide a means to verify operability of the NSPS functional circuits independent of the STS, and thereby (1) detect any failures undetected by the STS and take corrective action to restore proper operation of the NSPS and STS and (2) assuming that no additional failures beyond those identified by the STS are detected during the independent logic testing, confirm the validity of the STS test results. This independent testing in conjunction with rigorous preoperational testing of the STS is sufficient to verify that the STS is capable of performing its intended function to detect NSPS circuit failure conditions.

Response time tests (RTTs) are tests used to determine the time interval from when a monitored parameter exceeds its trip setpoint at the channel sensor until the actuated equipment is capable of performing its safety function; i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc. Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by any series of sequential, overlapping, or total steps so that the entire response time is measured. The STS will test the response time of the NSPS logic from the input of the analog trip modules to the output of the actuated device load driver in that the response time can be shown to be less than or equal to 1 millisecond each time that a test pattern is injected. All other control logic and logic not included in the above test will be tested by conventional response time testing methods. The total response time from the sensing element

to the actuated device will be the sum of the individual response times plus 1 millisecond for the solid-state logic. The maximum propagation delay (response time) through any logic channel in the NSPS will always be less than 1 millisecond or the STS will report a logic fault.

As stated in Supplement No. 2 or the SER, the STS will not detect failures within logic seal-in or latching circuits. These circuits will be tested by conventional methods before installation for those boards containing latching or seal-in circuits that cannot be verified operable by manually tripping and resetting the channel. Other circuits for which the STS will not detect failures include certain time delay and isolation circuits and the pulse-limiting capacitor/resistor circuits that momentarily block the NSPS functional inputs and strobe test data through the NSPS circuits. The above circuits have been identified as untested islands (UTIs). Periodic verification of the operability of these circuits must be performed separately. The General Electric Company (manufacturer of the NSPS and STS) and the applicant have identified all UTIs in the NSPS and have established procedures for testing the UTIs. The applicant has committed to periodically test all UTIs in accordance with the Clinton plant surveillance procedures using the test methods and frequencies recommended by the manufacturer.

The staff concludes that the Clinton Technical Specification operability and surveillance requirements and LCOs for the STS in conjunction with the required NSPS surveillance and procedures for testing the UTIs are sufficient to detect and correct failures within the NSPS safety-related circuits to ensure operability of the NSPS safety functions, and therefore, are acceptable.

The Clinton Technical Specifications contain a surveillance requirement for the solid state nuclear system protective system (NSPS) that manual testing, independent of the self-test system (STS), be performed so that all trip functions are tested at least once every four cycles. By letter dated May 19, 1986, the applicant requested that the manual testing requirement of the Clinton Technical Specifications commence after shutdown during the first regularly scheduled refueling outage instead of before fuel load. The applicant stated that sufficient manual testing of portions of the NSPS, independent of the STS, has been accomplished in the plant preoperational testing program to satisfy the manual testing requirements inherent in the applicable Clinton Technical Specification surveillances. The staff has reviewed the applicant's request and has determined that the manual testing of the NSPS performed during the preoperational testing program satisfies the Technical Specifications requirements and that it need not be repeated before fuel load.

It should be noted that Supplement No. 2 of the SER states that the STS annunciator window on the principal plant console will be activated at any time that the STS detects a failure in either itself or in the functional logic, and that if the failure is in the functional logic, an additional annunciator window will be lighted that identifies the system and the division or train in which the functional logic failure has been detected. A recent review of the STS by the applicant determined that in actuality, when a failure is detected in an NSPS division other than the division under test (i.e., a division other than the division with its STS acting as master), the fault is annunciated as being in the division that is master. The division that actually contains the failure has to be identified by plant personnel using a diagnostic terminal via the plant computer. The diagnostic terminal allows technicians to quickly isolate

a fault detected by the STS to the printed circuit (PC) card level. The applicant has committed to develop and implement design modifications to correct the STS design so that upon detection of a fault, the correct NSPS division will be annunciated as containing the fault, consistent with the description in Supplement 2 of the SER. However, because a significant amount of engineering effort is required to accommodate this change, the applicant will not implement the change until before startup after the first refueling outage. During the interim, the STS inputs to the divisional NSPS out-of-service alarms and test pulse fault indicators on control room panels P601 and P680 will be disabled in order to prevent erroneous information from being provided to the operator. The STS will be totally functional in accordance with the Clinton Technical Specifications during this interval, and all STS detected failures will be alarmed via the "STS Detected Failure" annunciator point on panel P680. The specific fault location will then be identified using the diagnostic terminal. The staff concludes that interim operation as discussed above is acceptable. The NRC Region III staff will follow up to ensure that the design modifications discussed above to correct the STS fault annunciation design are implemented before startup after the first refueling outage.

7.3 Engineered Safety Features Systems

7.3.3 Resolution of Issues

7.3.3.7 Engineered Safety Features Reset Controls

The staff previously reviewed the applicant's analysis concerning safety-related equipment changing modes upon reset of an engineered safety feature (ESF) actuation signal. The applicant has modified the control circuitry for most of the equipment so that returning safety-related equipment from its emergency mode to its normal operating status requires deliberate operator action after an ESF reset, and demonstrated that plant safety is not impacted for the remainder of the equipment. The staff concluded that the applicant's analysis and circuit modifications were acceptable, but required that the applicant submit control circuit drawings for the modified equipment. The applicant has submitted these drawings, and the staff performed an audit review of the circuit modifications for both nuclear steam supply system (NSSS) and balance of plant (BOP) equipment. The drawings indicate that the modifications have been made and are acceptable. Additionally, the applicant has stated that the equipment has been tested, as required by IE Bulletin 80-06, with specific procedural steps of each system's preoperational test, as well as the containment isolation preoperational test. The staff considers this issue to be resolved.

7.4 Safe Shutdown Systems

7.4.3 Resolution of Issues

7.4.3.1 Remote Shutdown System (RSS)

To comply with General Design Criterion (GDC) 19, "Control Room," the remote shutdown design should provide redundant safety-grade capability to achieve and maintain hot shutdown from a location or locations remote from the control room, assuming no fire damage to any required systems and equipment and assuming no accident has occurred. Credit may be taken for manual actuation (exclusive of continuous control) of systems from locations that are reasonably accessible

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from the remote shutdown panel. Credit may not be taken for manual actions involving jumpering, rewiring, or disconnecting circuits. The design should provide redundant safety-grade capability for attaining subsequent cold shutdown through the use of suitable procedures.

The Clinton RSS provides a means to achieve reactor hot shutdown and subsequent cold shutdown from outside the control room. The Clinton design includes a single remote shutdown panel (1C61-P001) located in the auxiliary building. Although the applicant does not consider the RSS to be a safety-related system, the components of the remote shutdown panel that interface with safety-related systems were designed and purchased to the requirements of the interfacing systems. The applicant did not originally design the RSS with the capability to withstand a single failure; however, additional instrumentation has been added, which, with the use of procedurally controlled manual manipulations of accessible equipment, will allow hot shutdown and subsequent cold shutdown given a single failure (including the loss of divisional power).

Using Division 1 power, the following systems can be operated and monitored from the remote shutdown panel:

- reactor core isolation cooling (RCIC) system - supplies makeup water for the reactor vessel
- nuclear boiler system - controls reactor pressure through the safety/relief valves
- residual heat removal (RHR) system (suppression pool cooling and shutdown cooling modes of operation) - controls suppression pool temperature and brings the reactor to its final, cold, low-pressure condition.
- shutdown service water system (SSWS) - supplies essential cooling water
- essential equipment cubical heating, ventilation, and air conditioning (HVAC) systems

Division 1 instrumentation provided to aid the operator in operation and control of the above systems includes:

- reactor water level indicator
- reactor pressure indicator
- drywell temperature indicators (2)
- suppression pool temperature indicators (3)
- diesel generator status lights
- diesel fuel oil transfer pump status lights
- RHR flow indicator
- SSWS strainer discharge pressure indicator
- SSWS strainer high differential pressure status light
- RCIC flow indicator
- RCIC turbine speed indicator
- RCIC turbine status lights
- RCIC storage tank level indicator
- suppression pool level indicator

The vertical indicators are classified as seismic Category I, and will remain operable after a seismic event.

The Division 1 portion of the RSS is electrically isolated from circuits located in the main control room so that fault conditions existing in control room circuits (that could result from an event causing an evacuation) will not preclude the capability to shut down the reactor from outside the control room. Manual transfer switches are provided for the equipment operable from the remote shutdown panel. When actuated, the transfer switches override controls in the main control room and transfer control to the remote shutdown panel. All necessary power supplies are also transferred. Remote shutdown control is not possible without actuation of the transfer devices. Operation of the transfer devices actuates an alarm in the main control room. Access to the remote shutdown panel is administratively controlled. The Clinton Technical Specifications will include operability and surveillance requirements, and associated limiting conditions for operation (LCOs) for all Division 1 instruments and controls relied on to achieve hot and subsequent cold shutdown from the remote shutdown panel. The staff concludes that the Divison 1 remote shutdown capability at Clinton is acceptable.

Because the original Clinton design provided only for the transfer of Divison 1 systems to the remote shutdown panel, subsequent modifications were necessary to provide Division 2 remote shutdown capability. Division 2 controls for three safety relief valves were added to allow operation from the remote shutdown panel. Division 2 instrumentation added to the panel allows monitoring of the following parameters:

- reactor water level
- reactor pressure
- suppression pool temperature
- suppression pool level
- RHR flow
- SSWS strainer discharge pressure

The Division 2 controlled safety relief valve controls are provided with manual transfer devices similar to those provided for Division 1 equipment. The Division 2 controls and indicators are classified as seismic Category I equipment.

Insufficient capability exists to bring the reactor to hot shutdown and subsequent cold shutdown using Division 2 instruments and controls at the shutdown panel. Therefore, the applicant developed a procedure to be used to achieve a safe shutdown condition by actuating Division 2 equipment, either locally or from switchgear or motor control centers (MCCs), in the vicinity of the remote shutdown panel in the unlikely event of remote shutdown with the loss of Division 1 power. The Division 2 equipment used includes the RHR system pump and valves (~13 valves), the SSWS pump and SSWS to plant service water system isolation valve, and the SSW pump room ventilation fan. The procedure for using Division 2 equipment, however, involves methods of equipment actuation that the staff considers unacceptable. These methods include pulling fuses, lifting leads, and installing jumpers. Subsequently, the applicant determined that operation of Division 2 equipment in this manner was only necessary for four components: the RHR pump, the SSWS pump, the SSWS pump room ventilation fan, and one of the RHR system valves. The remaining Division 2 valves, are located in low-radiation areas, are readily accessible, and can be actuated by manual operation of the valve operator handwheel.

By letter dated April 21, 1986, the applicant committed to implement design modifications before startup after the first refueling outage to eliminate the

need for using jumpers, rewiring, or disconnecting circuits when effecting shutdown from outside the control room using Division 2 equipment. These modifications will consist of adding control switches to the switchgear and MCCs for operation of Division 2 equipment where needed, and the corresponding changes to the remote shutdown procedures. Additionally, the applicant has committed to Technical Specification operability and surveillance requirements, and associated LCOs for all Division 2 instruments and controls. These Technical Specifications will be similar to those for Division 1 RSS equipment.

The staff concludes that the above modifications for Division 2 RSS equipment are acceptable to resolve concerns regarding the use of jumpers, rewiring, and disconnecting circuits, and that following implementation, the Clinton RSS design will be in conformance with the guidance provided in Section 7.4 ("Safe Shutdown Systems") of the Standard Review Plan (NUREG-0800) and, therefore, acceptable. In the interim (during the first fuel cycle), the applicant will continue to rely on existing procedures involving the use of jumpers, rewiring, and pulling fuses for the four components identified above. The staff concludes that operation of the four components in this manner is acceptable on the basis of the following:

(1) the applicant's commitment in its April 21, 1986, letter to modify the RSS design to eliminate the use of jumpers, rewiring, and disconnecting circuits as discussed above

(2) the applicant's commitment in its April 21, 1986, letter to train the operators on the procedures for remote shutdown using Division 2 controls and equipment, including the precautions for local operation of controls currently requiring jumpering, rewiring, or disconnecting circuits (this training will include classroom sessions and practical field applications but will not involve actual energizing/exercising of equipment)

(3) the applicant's commitment in its April 21, 1986, letter to perform testing before power operation which demonstrates the acceptability of the remote shutdown procedures for actuation of the four components (Note: this testing will verify operability of the actuation devices, e.g., pump breakers, but may not involve actual equipment or system operation)

(4) the low probability of an event requiring evacuation of the main control room coupled with a loss of Division 1 power (thus requiring the use of Division 2 remote shutdown equipment) occurring during the first fuel cycle

The NRC Region III staff will verify that the modifications described above to eliminate the need for using jumpers, rewiring, or disconnecting circuits have been implemented by the applicant before startup after the first refueling outage.

7.5 Information Systems Important to Safety

7.5.3 Resolution of Issues

7.5.3.2 Safety Parameter Display System

By letter dated June 11, 1986, the applicant stated that the safety parameter display system (SPDS) design as approved by the staff in Supplement 5 to the

SER had to be modified. The design modification is related to the display of the containment isolation valve group status and isolation valve grouping. In the SPDS "Dynamic Simulation Test Results Report," which the staff utilized in its evaluation, it was noted in the operator comment section that the number of isolation valve groups had been changed from 11 to 13. The original 11 containment isolation valve groups and the valves within those groups were based on requirements for the Clinton Off-Normal Procedure (No. 4001.02) for "Automatic Isolation." Evaluation for appropriate groupings for all the automatic primary containment isolation valves presently in the FSAR (through Amendment 38) by the applicant and changes to the "Automatic Isolation" procedure have resulted in the applicant identifying 51 primary containment automatic isolation valves which are not currently statused by the appropriate valve groups on the SPDS. Of these 51 valves, 47 presently provide signal input to the plant process computer. The applicant has stated that the SPDS will be modified to include these 47 primary containment isolation valves before exceeding 5% of rated power. The remaining 4 valves will require field wiring to the plant process computer. The applicant has stated that the addition of these 4 primary containment isolation valves to the SPDS will be completed before startup after the first regularly scheduled refueling outage.

The applicant in its June 11, 1986, letter also stated that these 51 valves and the primary containment isolation valves currently statused on the SPDS will be regrouped into 13 valve groups which are based on valves with common automatic isolation signals. These changes to the isolation valve groups also require changes to the main control room isolation valve group annunciator display tiles. The applicant has stated these changes will be completed before exceeding 5% of rated power.

The staff has evaluated the changes to the SPDS as described in the applicant's June 11, 1986, letter and agrees with the applicant's conclusion that these SPDS changes do not affect the conclusions reached by the staff in Supplement 5 to the SER regarding the acceptability of the SPDS. The staff has also reviewed the applicant's schedule for completion of these changes to the SPDS and finds it acceptable. However, on the basis of the applicant's changes to the SPDS, the staff recommends the following license condition (license condition 21).

> The SPDS modifications related to the display of the containment isolation valve group status in the main control room and the incorporation of the 51 additional valves and the isolation valves currently statused on the SPDS into 13 groups shall be completed on the schedule contained in the applicant's June 11, 1986, letter.

Region III shall verify the completion of the SPDS design modifications described in the applicant's June 11, 1986, letter.

7.7 Control Systems

7.7.3 Resolution of Issues

7.7.3.1 Effects of Control System Failures

As stated in the SER, the applicant committed to provide the results of its control system failures review before fuel load. This is related to SER outstanding issue 15. To reiterate from the SER, the staff requested that the

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applicant identify any power sources, sensors, or sensor impulse lines which provide power or signals to two or more control systems and demonstrate that failures of these power sources, sensors, or sensor impulse lines will not result in consequences outside the bounds of the FSAR Chapter 15 analyses. In addition, the applicant was asked to review the designs to determine whether harsh environments associated with high-energy line breaks (HELBs) might cause control system malfunctions resulting in consequences more severe than those analyzed in FSAR Chapter 15.

By letter dated December 9, 1982, the applicant provided the results of its initial review effort associated with the control system failures issue. It was concluded by the applicant in its initial analyses that the Chapter 15 events were bounding and that all safety criteria were met despite simultaneous control system failures. However, since the staff issued requests for additional information (letter dated March 18, 1986) resulting from review of the initial analyses, the applicant has determined (response letter dated April 17, 1986) that additional effort would be required to fully resolve this issue. Thus, the applicant has initiated an in-depth re-review of the original control systems failure analyses to provide assurance that the worst-case combined effects of multiple control system failures were considered and to reconfirm that unanalyzed events do not exist.

The applicant, by letter dated May 15, 1986, committed to provide the results of its re-review effort to the staff before startup after the first refueling outage. This will include the identification of all the control systems which could impact the Chapter 15 analyses, a summary of the event(s) resulting from postulated combined worst-case failures, and the identification of the specific Chapter 15 analysis which bounds the resulting consequences. By letter dated July 16, 1986, the applicant committed to provide the results of its re-review effort and any corrective actions that may be found necessary for staff review 4 months before startup after the first refueling outage. In addition, the applicant committed to implement any corrective actions that may be found necessary before startup from the first refueling outage. Plant operation before completion of the applicant's additional evaluation is acceptable because: (1) staff review of other similar nuclear facilities has not revealed failure modes with consequences more severe than those analyzed in the FSAR and (2) the applicant's preliminary assessment of simultaneous malfunctions which indicates that the consequences are bounded by the existing analyses of FSAR Chapter 15.

The staff finds the applicant's planned program to address this issue to be acceptable. However, the Clinton operating license shall be conditioned (License Condition 23) as follows:

> The applicant shall submit the results of the additional evaluation of control system failures and the proposed implementation of any corrective actions that may be found necessary, for staff review 4 months before plant startup after the first refueling outage. Implementation of any corrective actions found acceptable by the staff shall be completed before plant startup after the first refueling outage.

On the basis of the above discussion, including incorporation of the above license condition, the staff considers Clinton SER outstanding issue 15 to be resolved.

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7.7.3.2 Instrument Sensing Line Freeze Protection

In the construction phase Safety Evaluation Report (NUREG-75/013), Section 7.8, the NRC staff identified a concern that the reactor core isolation cooling (RCIC) storage tank level instrument sensing line was not adequately protected against freezing. The level signal is used to transfer RCIC and high-pressure core spray (HPCS) pump suctions from the RCIC storage tank to the suppression pool. The applicant was committed to provide additional instrumentation that would automatically transfer the water source on either low tank temperature or low suction piping temperature. In a letter dated September 3, 1985, the applicant provided a description of the freeze protection design for the RCIC storage tank and the level sensing line and justification that the automatic transfer of RCIC or HPCS suction to the suppression pool on low temperature is no longer necessary.

The applicant has stated that four level transmitters are provided to automatically initiate transfer of the RCIC and HPCS pump suctions from the RCIC storage tank to the suppression pool when water level in the tank is low. These level transmitters sense tank level via a 4-inch-diameter instrument line which passes through the pipe tunnel and into the fuel building. The only instrument line that has potential exposure to freezing temperature is the 4-inch-diameter line through a 17-foot-long pipe tunnel. This instrument has a low-temperature alarm in the main control room. The alarm, which is set at 45°F, is based on the outputs from two temperature elements installed in the instrument line. The pipe tunnel is constructed with insulated siding and has a concrete floor. The tunnel is heated by a 10-kW space heater to maintain the tunnel at 65°F during cold weather. The tank is provided with two 12-kW electric immersion heaters. Tank water temperature is controlled by a temperature-indicating controller (TIC). Low temperature will be alarmed in the main control room based on the outputs from two in-tank temperature elements set at 45°F. The power sources for tank heaters, pipe tunnel area heater, tank low-temperature alarm, and instrument line low-temperature alarm are from different motor control centers. The plant operating procedures will require manual RCIC and HPCS pump suctions to transfer to the suppression pool when either the tank or the piping low-temperature alarms annunciate in the main control room. To preclude the possibility of long-term heater inoperability, the surveillance procedure has been revised to include a log of tank water temperature, TIC setpoint, and heater status every 8 hours, whenever ambient temperature is below 32°F. Proper operation of the pipe tunnel heater will also be checked every 8 hours.

The staff has reviewed the information provided by the applicant and has determined that the freeze protection of the RCIC storage tank level instrument line is in conformance with Regulatory Guide 1.151, "Instrument Sensing Lines." Except for the 4-inch-diameter instrument line, the instrument taps, transmitters, and other smaller instrument lines are all located inside the fuel building which is heated. The plant operating procedures will require the operator to manually transfer RCIC and HPCS pump suctions from the RCIC storage tank to the suppression pool whenever the tank or piping experiences low temperatures. On the basis of the above information, the staff concludes that the justification to delete the automatic transfer of the RCIC and HPCS pump suctions due to a low- temperature condition is acceptable.

8 ELECTRIC POWER SYSTEM

8.2 Offsite Power System

8.2.3 Adequacy of Station Electric Distribution System Voltages

In the SER, the staff discussed the applicant's conformance to the positions contained in Branch Technical Position (BTP) PSB-1. The applicant has subsequently provided revised responses to show conformance to two of those positions. The following items (numbered to correspond with the positions contained in the BTP) provide the staff's evaluation of those revised responses.

(2) The staff stated in the SER that load shedding of the diesel generator will be blocked when the diesel is supplying the loads. In Amendment 33 to Section 8.3.1.1.2 of the FSAR, the applicant has deleted the statement that supports this. In the same amendment, the response to a staff question relative to this subject was revised. The applicant now states that spurious transfers are precluded by the 69% setting of the loss of power relays, which is sufficiently lower than the minimum transient voltages that occur while starting motors from the offsite or onsite sources. Because the staff's concern on this issue is that the loss of power relays may cause spurious load shedding of safety loads from the diesel generators on motor starting transients, the applicant's response is acceptable.

(4) The staff stated in the SER that the applicant had committed to do the verification testing in accordance with the guidelines provided in part 4 of the staff position. In a subsequent letter dated June 12, 1985, the applicant provided a revised response to the staff question on this subject which proposes to reduce the scope of the voltage verification test conducted. The purpose of the verification test is to verify, by actual measurement, the analytical techniques and assumptions used in the voltage analysis called for in position 3 of the BTP. In this regard, the applicant states that the same voltage calculation procedure that was used at Clinton was also used at Commonwealth Edison's Zion Power Station. The staff has previously reviewed and approved the verification test results at Zion. In addition, the applicant states that the transformer, cable, and bus duct impedances are actual values of equipment in use at Clinton obtained from certified test reports and drawings supplied by the vendor. The applicant also still intends to take measurements on one string of safety buses from the 4160-volt level down through and including a 120-volt distribution panel. The measurements taken include the voltage across a 120-volt valve motor contactor coil. All the measurements will be compared with the calculated results. The staff concludes that the reduced scope of the voltage verification test to be conducted at Clinton, together with the previously approved verification test at Zion, will adequately verify the voltage calculations at Clinton.

8.3 Offsite Emergency Power Systems

8.3.1 AC Power System

In a letter dated May 24, 1985, the applicant requested approval for an alternate method of meeting the intent of position C.2.a.(5) in Regulatory Guide (RG) 1.108. This position requires that immediately following a 24-hour load test the capability of the diesel generator to automatically start, come up to speed, and load its accident loads within the required limits be demonstrated. The applicant has requested the option of running the start and load test following the 24-hour test or following a run of the diesel generator at 100% power for a sufficient period of time to ensure that the units have reached a stabilized temperature. This option is in accordance with the staff's requirements contained in Standard Technical Specifications and meets the intent of the RG 1.108 requirement and is, therefore, acceptable.

In its SER, the staff stated that the diesel generator circuit breaker should not be locked out when the diesel generator is being tested in parallel with the offsite power system and a subsequent loss of offsite power occurs. The applicant provided a scheme for bypassing the lockout, and the staff accepted it on the basis that it be incorporated into the Division 1 and 2 diesel generator design (Division 3 was already acceptable). During the staff's visit to the site on October 29 and 30, 1985, the staff reviewed with the applicant the design of this circuitry as shown on drawings E02-1DG99, sheets 11 and 28, and E02-1AP99, sheets 13 and 14. The design as implemented will not trip or lock out the diesel generator or its circuit breaker when the diesel generator is being tested in parallel with offsite power and a subsequent loss of offsite power occurs. Instead, the offsite power circuit breaker is tripped. The staff finds this acceptable.

8.3.2 DC Power Systems

In Section 8.3.2 of the SER, the staff stated that not all of the Division 3 dc loads have been specified for operation at the 140-volt dc equalizing charge voltage. The report then described how the loads which were not rated up to 140 volts would be disconnected from the battery while it was undergoing an equalizing charge.

In Amendment 29 to the FSAR, the applicant revised its response to a staff question relating to equalizing charge voltages. The applicant now states that the maximum equalizing charge voltage for the Division 3 battery will be 137.4 volts. Furthermore, the applicant states that all dc equipment on the Division 3 dc bus is specified for operation at this voltage. It is, therefore, no longer necessary to disconnect any equipment from the Division 3 battery while it is undergoing an equalizing charge. The staff finds this acceptable.

8.4 Other Electrical Features and Requirements for Safety

8.4.5 Nonsafety Loads on Emergency Sources

Amendment 33 to the Clinton FSAR stated that non-Class 1E non-division associated components are electrically isolated from the Class 1E system by an acceptable isolation device except where justified by analysis. In a letter dated January 24, 1986, the applicant provided these analyses to the staff for

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its review. The analyses consist of Sargent and Lundy Calculations 19-BD-1, 2, 5, 7, 8, 10, 11, 12, 13, 15, 16, and 17. The analyses address miscellaneous cases of insufficient separation distances between circuits, and interfaces between Class 1E components and components that are not Class 1E. Some of the analyses on separation distances have subsequently been supplemented by the more comprehensive tests and analyses performed by the applicant as discussed in Section 8.4.7 below. The staff has reviewed the submitted analyses and finds them acceptable.

In Section 8.4.5 of the Clinton SER, the staff stated that circuit breakers and fuses actuated only on fault currents and used as isolation devices between non-safety loads and emergency power sources would be tested in a similar way to the required testing contained in the Technical Specifications for penetration fuses and circuit breakers. Later the staff deleted the requirements contained in Standard Technical Specifications relative to the testing of penetration fuses. Therefore, the testing of fuses used as isolation devices is also no longer required. The testing of circuit breakers actuated only by fault current and used as isolation devices should be continued; however, it need not be contained in the Clinton Technical Specifications. In a letter dated February 13, 1986, the applicant committed to provide the required testing of the circuit breakers in the Clinton maintenance procedures. The staff finds this acceptable.

8.4.7 Physical Identification and Independence of Redundant Safety-Related Electrical Systems

In the SER, the staff described the separation provided for the electrical cable systems at Clinton, which in general complied with the standard separation distances recommended in IEEE Standard 384-1974. In a subsequent letter dated March 10, 1986, the applicant provided justification for separation distances which were less than originally committed to. The justification is in the form of an analysis (Calculation No. 19-BDA-1, Rev. 3, dated February 11, 1986) which is supported by tests that are referenced in the analysis. This approach to establishing separation distances conforms to one of the options given in IEEE 384-1974.

The staff has reviewed the analysis and the test supporting results. The analysis identifies minimum separation distances for various cable routing configurations. These distances and configurations are based on similar configurations tested during the test phase. The tests consisted of setting up various cable routing configurations representative of those configurations normally seen in the plant. A fault current is then applied to one of the cables in the configuration while its effect on cables (designated as target cables) in adjacent trays, conduits, or free air is monitored. At the conclusion of the test, the target cables are checked for dielectric strength and insulation resistance.

The fault current level chosen for conduct of the tests was based on a typical locked rotor current which would occur in a motor fed by a 500 MCM cable. This is conservative since a higher level of fault current that would create a higher level of instantaneous heating of the fault cable would also be cleared quickly by tripping of the upstream backup breaker (assuming the primary breaker fails) or fusing open of the fault cable. The locked rotor current value on the other hand is below the trip value of the upstream backup breaker and will not cause the fault cable to quickly fuse open. During the tests, the locked rotor value of fault current (1300 amps) was imposed on the 500 MCM fault cable

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for a period of 1 hour. After this, the current was increased to a value of 1700 amps for an additional 2 hours or until the cable fused open. This level of fault current is still below a point which would cause tripping of the back-up breaker or rapid fusing open of the fault cable.

Target cables in some of the tested configurations failed by open-circuiting, demonstrated a complete voltage breakdown in the functional tests, or sustained substantial insulation damage. As a result of these failures, additional configurations were tested with more conservative distances and orientation used. With the exception of one target cable, all the remaining target cables in the additional tests satisfactorily passed the tests. The final separation distances proposed for Clinton are based only on the tested configurations which showed satisfactory results. These distances are defined in Figure 1 of the calculation submitted in the applicant's January 24, 1986, letter.

The staff has reviewed the separation distances proposed for Clinton and the tests and analyses which support them, and finds them acceptable.

During its visit to Clinton, the staff also examined the use of flexible conduit in control room panels. The conduit is used as a separation barrier to meet the requirements of IEEE 384-1974 where 6 inches cannot be maintained between redundant circuits or between a Class 1E and non-Class 1E circuit. Where the conduit is run in the power generation control complex (PGCC) floor sections and brought up into the panel, the staff has approved its use as discussed in Section 8.4.7 of Supplement 1 to the SER. Where the flexible conduit is only run internal to the cabinet, the staff considers its use as a barrier acceptable because of the low energy levels of the circuits involved (maximum is 125-V dc or 120-V ac control or lighting), the generally exposed configurations of the conduit (not buried under cables as in the PGCC floor sections), and the limited runs of conduit involved (less exposure for a line-to-conduit fault).

The staff, therefore, considers the use of flexible conduit as a separation barrier for circuits in control room panels to be acceptable.

In Section 8.4.7 of Supplement 1 to the SER, the staff required that the fuses and circuit breakers used to protect the circuits run in flexible conduit and routed in the PGCC floor sections be periodically tested and that this testing be incorporated into the Clinton Technical Specifications. As explained in Section 8.4.5 above, the staff has deleted the requirements for fuse testing. The testing of circuit breaker overcurrent trip elements in this application should be continued; however, it need not be contained in the Clinton Technical Specifications. In a letter dated February 13, 1986, the applicant committed to provide the required testing of the circuit breakers in its plant maintenance procedures. The staff finds this acceptable.

9 AUXILIARY SYSTEMS

9.1 Fuel Storage Facility

9.1.1 New Fuel Storage

By letter dated August 7, 1985 (W. Crowe, NRC, to D. Hall, IP), the staff issued Special Nuclear Material (SNM) License No. SNM-1886, which authorized the applicant to receive, possess, inspect, and store uranium enriched in the U-235 isotope contained in fuel assemblies. This license authorized the storage of the fuel assemblies in their shipping containers and in the spent fuel storage facility.

In its application for the SNM license, the applicant requested various authorizations regarding the receipt, possession, inspection, and storage of the fuel assemblies. Additionally, in a separate request, the applicant requested an exemption from the requirements of 10 CFR 70 regarding nuclear criticality safety. These issues were identified in the safety evaluation included with the SNM license and its amendment and were incorporated into the SNM license via license conditions. As stated in SNM-1886, the SNM license expires upon conversion of the construction permit to an operating license. The staff has determined that specific conditions in the 10 CFR 70 license (SNM license) related to the storage and handling of fresh fuel assemblies equally apply to the 10 CFR 50 operating license. These conditions, their bases, and how they will be incorporated into the 10 CFR 50 operating license are discussed below:

Shipping Container Storage

Fuel assemblies may be temporarily stored in their inner and outer shipping containers or only in their inner containers. The shipping containers will not be stacked more than 3 layers high; no more than 24 containers will be in a single array. The safety evaluation accompanying the SNM license stated that the applicant has committed to maintain a minimum of 25-foot spacing between groups of 24 shipping containers. Nuclear criticality safety is ensured because the safety of fuel stored in inner shipping containers in an infinite array stacked four high has been established (Amendment No. 5 to Materials License No. SNM-1097, dated June 6, 1978, Docket No. 70-1113). The 25 feet of separation between arrays is adequate for isolation between arrays.

Fuel Handling

The safety evaluation accompanying the SNM license stated the following:

> The applicant plans to have no more than three fuel assemblies outside their shipping containers or storage racks at one time. However, the applicant did not specify the minimum distance between this grouping of assemblies and all other fuel. The NRC staff has shown that three isolated fuel assemblies cannot be made critical independent of the spacing between them and of the degree of water moderation and/or reflection. The staff has also determined that a separation of at least 12 inches between the grouping of three fuel assemblies, and

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all other fuel assemblies in their shipping containers or storage rack locations, is required to assure the nuclear criticality safety of the arrays, under all degrees of water moderation and/or reflection. Accordingly the staff recommended that the following license conditions be added to ensure nuclear criticality safety by (1) limiting the number of fuel assemblies out of storage and (2) maintaining a minimum edge-to-edge distance between fuel out of storage and all other fuel.

Condition 15: No more than three fuel assemblies shall be outside their shipping containers and storage racks at any one time.

Condition 16: The minimum edge-to-edge distance between the group of three fuel assemblies and all other fuel assemblies shall be 12 inches.

These license conditions were incorporated into the SNM license and identified as license conditions 15 and 16. The staff has determined that these conditions equally apply to the 10 CFR 50 operating license; however, Condition 15 should be expanded to specify that no more than three fuel assemblies shall be out of approved shipping containers or fuel assembly storage racks or the reactor at any one time. Accordingly, SNM-1886 license conditions 15 and 16 should be incorporated into the operating license as a license condition, to read as follows:

No more than a total of three (3) fuel assemblies shall be outside their shipping containers or storage racks or the reactor at any one time.

The minimum edge-to-edge distance between the group of three fuel assemblies and all other fuel assemblies shall be 12 inches.

New Fuel Storage Vault

The safety evaluation accompanying the SNM license stated the following:

The new fuel racks in the new fuel storage vault are designed to store up to 240 fuel assemblies. There are 24 rows and 10 fuel assemblies per row. The center-to-center spacing between assemblies is 7 inches within a row and 12.25 inches between rows. The applicant's and the NRC staff's criticality calculations were for infinite arrays at all moderator densities. Calculations of k_{eff} for the array were independently performed by the NRC staff. The staff calculated the array to be supercritical when enveloped in mist with a density between 0.01 g/cm^3 and 0.15 g/cm^3 (approximate densities). If the entire array were flooded with full density water, k_{eff} of the array would be approximately 0.82.

The applicant has provided four aluminum plate covers over the vault to prevent the entry of mist. Further, no more than two of the covers would ever be off the vault and expose no more than 12 rows (120 assemblies) of fuel assemblies. The applicant has stated in the FSAR that covers will normally be in place over the vault except when new fuel

is to be inserted or removed from the rack. Since it has been estimated by the staff that an array of as few as five rows of assemblies fully flooded with water mist at optimum density for maximum k_{eff} may become critical, the applicant has installed firehose protection stations equipped with solid stream nozzles to fight fires that may, but are unlikely to, occur in the vault. The applicant has committed to establish station administrative procedures specifying actions to be taken for control of combustibles, control of ignition sources, and to control action to be taken in the event of a fire.

Accordingly a license condition was incorporated into the SNM license and identified as license condition 17. The staff has determined that this condition equally applies to the 10 CFR 50 operating license and, accordingly, SNM-1886 license condition 17 should be incorporated into the operating license as a license condition, to read as follows:

Fuel assemblies, when stored in the new fuel storage vault, shall be stored under the following conditions:

(a) No more than 12 rows of fuel assemblies shall remain uncovered during the loading or unloading of fuel assemblies.

(b) Metal covers shall cover all other rows containing fuel assemblies during loading and unloading of fuel assemblies.

(c) When loading or unloading of fuel assemblies is not in progress, metal covers shall cover all rows of fuel assemblies.

The safety evaluation accompanying the SNM license also stated that the applicant plans to wrap the new fuel assemblies in polyethylene sheeting to protect them from the environment while in storage. The fuel assemblies may become internally moderated with water; the spaces between assemblies would be occupied only with air. This could occur if the storage area flooded, the area then drained, and the water was retained in the plastic bags. Under these conditions, the array may become critical. The applicant plans to have the polyethylene sheets open at both ends to enable water to drain freely from the fuel assemblies. Under these conditions, there is no nuclear criticality hazard from full density flooding (water) and subsequent draining. To further ensure the applicant's action to prevent such a situation from occurring, a license condition was incorporated into the SNM license and identified as condition 19. The staff has determined that this condition equally applies to the 10 CFR 50 operating license and accordingly SNM-1886 license condition 19 should be incorporated into the operating license as a license condition, to read as follows:

Fuel assemblies shall be stored in such a manner that water would drain freely from the assemblies in the event of flooding and subsequent draining of the fuel storage area.

Upper Containment Fuel Storage Pool

The safety evaluation accompanying the SNM license stated the following:

> The upper containment fuel storage pool has the same design as the new fuel storage vault. Therefore, k_{eff} of fresh fuel stored in this pool is is the same at all water mist densities as it is in the new fuel storage vault (assuming infinite arrays). Since the k_{eff} of the array is only 0.82 when flooded with full-density water, the applicant presently plans to store fresh fuel assemblies in this pool only under water.

Accordingly a license condition was incorporated into the SNM license and identified as license condition 20. The staff has determined that this condition equally applies to the 10 CFR 50 operating license and, accordingly, SNM-1886 license condition 20 should be incorporated into the operating license as a license condition, to read as follows:

> Fresh fuel assemblies shall be stored in the containment fuel storage pool only under water.

Fuel Building Spent Fuel Storage Pool

The safety evaluation accompanying the SNM license stated the following:

> The racks in the spent fuel storage pool form a square array of storage cells spaced on 6.4375-inch centers. The walls that separate storage locations are composed of two steel sheets with a nominal thickness of 0.060 inch, welded to each other to form a pocket 0.150-inch wide in which a 4.25-inch wide by 0.11-inch thick Boral poison sheet is placed for criticality control. The Boral plates contain boron with an areal density of 0.030 g B-10/cm^2. The inner diameters of the storage cells are 6.1675 inches. The layers of steel and Boral provide a margin of safety to prevent an inadvertent criticality.
>
> The staff determined the maximum k_{eff} for an infinite array of fuel assemblies in the spent fuel storage pool to be 0.0840 ± 0.004 at the optimum degree of water moderation (full-density water) within and between assemblies. Therefore, any size array of fuel assemblies in the spent fuel storage pool is safe from inadvertent criticality under all degrees of water moderation. The applicant has a quality assurance program starting with the certification of the analysis of the Boral plates, continuing with the manufacturing of the plates, their installation in the spent fuel racks, and the surveillance program to ensure their continued presence in the racks. The NRC staff resident inspectors have confirmed the Boral meets the above specifications and has been fabricated into plates which were installed in the storage racks in their design positions.

Since the applicant stated it has no intention "at this time" to store fuel assemblies in the control rod racks and the staff was not supplied with sufficient information to evaluate the nuclear criticality safety of these racks if

loaded with fuel assemblies, license condition 21 was added to the license. The staff has determined that this condition equally applies to the 10 CFR 50 operating license and, accordingly, SNM-1886 license condition 21 should be incorporated into the operating license as a license condition to read as follows:

> No fuel assemblies shall be stored in the control rod racks.

Exemption From Criticality Alarm Requirements

In connection with its application for an SNM license, the applicant requested, pursuant to 10 CFR 70.24(a), an exemption from the provisions of 10 CFR 70.24. Because of the inherent features associated with the storage and inspection of unirradiated fuel containing uranium enriched to less than 5% in the U-235 isotope when no fuel processing activities are to be performed, the staff determined that granting such an exemption is authorized by law, will not endanger life or property or the common defense and security, and is otherwise in the public interest. Additionally, the staff found that this exemption is authorized pursuant to 10 CFR 70.24. Accordingly, the staff recommended that the exemption be identified as SNM-1886 license condition 24:

> The licensee is hereby exempted from the provisions of 10 CFR 70.24 insofar as this section applies to materials held under this license.

By letter dated November 27, 1985, the SNM license was subsequently amended to include this exemption. The staff recommends that this exemption be added to the operating license.

9.1.2 Spent Fuel Storage

In connection with the application for a special nuclear materials license under 10 CFR 70, the applicant had requested, pursuant to 10 CFR 70.24(d), an exemption from the provisions of 10 CFR 70.24, which requires criticality monitors in areas where fuel is handled or stored. On the basis of the applicant's demonstration of subcriticality under normal and accident conditions, good cause was shown and the exemption from the requirements of 10 CFR 70.24 for storage of new or spent fuel in the spent fuel storage racks was granted in License Number SNM-1886.

The following features are inherently associated with the storage and inspection of unirradiated fuel containing uranium enriched to less than 5% in the U-235 isotope when no fuel processing activities are to be performed. These formed the basis for granting the exemption.

(1) Fuel assemblies are handled as discrete items. Only one fuel assembly is handled at one time and only three assemblies can be out of approved storage at one time. The NRC staff has shown that three isolated boiling-water reactor (BWR) fuel assemblies cannot be made critical independent of the spacing between them and of the degree of water moderation and/or reflection.

(2) Normally the new fuel assemblies are stored dry. Under these conditions, an infinite number of assemblies containing uranium enriched to less than 5% in the U-235 isotope cannot be made critical, independent of the spacing between them.

(3) There are engineered controls for the spacing between fuel assemblies in the fuel storage racks in the upper containment, spent fuel storage pools, and in the new fuel vault. In the spent fuel storage racks in the spent fuel storage pool, racks are designed so that the array of fuel assemblies cannot be made critical independent of the degree of water moderation between them (maximum k_{eff} for an infinite array is 0.840±0.004). The new fuel assemblies are stored in the racks in the upper containment fuel storage pool only under water (10 CFR 70 license condition 20). Under these conditions, the k_{eff} of the array is 0.82. Administrative controls for the storage of new fuel assemblies in the new fuel storage vault (10 CFR 70, license conditions 17 and 18) ensure nuclear criticality safety. The number of fuel assemblies that can be uncovered at one time is limited and all fire hoses servicing the new fuel storage vault area are equipped with solid stream nozzles. These conditions preclude the possibility of moderating an entire open section of the fuel array and from generating mist over the entire exposure array to assure nuclear criticality safety in the vault.

(4) Fuel assemblies are packaged in plastic wrappers open at both ends so that water would drain freely from the assemblies in the event of flooding and subsequent draining of the fuel storage area. This administrative control removes the possibility of criticality under these postulated accident conditions.

Because of the inherent features associated with storage and inspection of fuel containing uranium enriched to less than 5% in the U-235 isotope when no fuel processing activities are to be performed, the staff has determined that continuance of the exemption will not endanger life or property or the common defense and security, and is otherwise in the public interest. This exemption is authorized pursuant to 10 CFR 70.14. The staff recommends that this exemption be added to the operating license.

9.1.3 Spent Fuel Pool Cooling and Cleanup System

(1) Pump Motors

In FSAR Amendment 36, the applicant noted that both the spent fuel pool cooling pump motors (1A and 1B) were not qualified for a post-LOCA environment (temperature in excess of 104°F) as required by 10 CFR 50.49. The applicant has committed to install replacement motors by the first refueling outage. Since spent fuel is not expected to be installed in the pool until the refueling has started, qualified motors are not required until then. The staff finds this to be acceptable. Regional NRC inspectors will verify that the plant does not operate in any mode other than Mode 5 (refueling mode) with spent fuel in either the upper containment pool or in the spent fuel pool until after spent fuel pool pump motors capable of operating in the post-LOCA environment are installed and have been tested to ensure satisfactory operation.

(2) Heat Loads

The original SER indicated that the maximum abnormal heat load for the spent fuel pool is based on unloading a full core 134 hours after the last refueling outage. However, the applicant had also stated (in FSAR Section 9.1.3.3,

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"Safety Evaluation") that the maximum possible normal decay heat load is that of a full core at the end of the fuel cycle plus that from the spent fuel discharged from 13 previous refuelings which amounts to 50.33×10^6 Btu/hr. The applicant has reported that by utilizing the shutdown service water system to cool one spent fuel pool heat exchanger while utilizing the component cooling water system to cool the other spent fuel pool heat exchanger, an effective cooling rate of 52.9×10^6 Btu/hr. can be attained.

The applicant also noted that the temperature of the spent fuel pool water may be permitted to rise to 150°F under the circumstances of maximum heat load. Additionally, the operator may connect the fuel pool cooling and cleanup system to the residual heat removal (RHR) system in the event the spent fuel pool temperature exceeds 150°F. The staff finds this acceptable.

9.2 Water Systems

9.2.7 Turbine Building Closed Cooling Water System

There is no specific section of the Standard Review Plan (SRP) that provides guidelines for the review of the turbine building closed cooling water (TBCCW) system. Therefore, SRP Section 9.2.2, "Reactor Auxiliary Cooling Water Systems," was used as a guide for reviewing the system.

The TBCCW system is a closed-loop system designed to cool station auxiliary equipment in the turbine and radwaste building. It is not required for plant shutdown or for the mitigation of accidents or transients and, thus, is not designed to the standards required for safety-related equipment.

The TBCCW system uses demineralized water which is treated by a chemical inhibitor to minimize system corrosion and fouling. The TBCCW storage tank is equipped with a level transmitter with which the control room operator may monitor the tank contents.

Adjacent safety-related equipment is protected from missiles and flooding resulting from equipment failures or breaks in the TBCCW system as required by SRP Section 3.5.1.1, "Internally Generated Missiles (Outside Containment)," and 3.6.1, "Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment," and General Design Criterion (GDC) 4, "Environmental and Missile Design Bases."

Therefore, the staff finds that the design of the TBCCW system is acceptable.

9.2.8 Chilled Water Systems

9.2.8.1 Control Room Chilled Water System

There is no specific section of the Standard Review Plan (SRP) that provides guidelines for the review of the control room chilled water (CRCW) system. Therefore, SRP Section 9.2.2, "Reactor Auxiliary Cooling Water Systems," was used as a guide for the review of the system.

The CRCW system is designed to provide sufficient chilled water to the control room HVAC system and control room HVAC equipment room to maintain temperatures suitable for operators and equipment in the control room and adjacent areas.

It is a safety-related system; the system components are designed in accordance with the criteria specified for Safety Class C, seismic Category I components. Electrical equipment is designed in accordance with the standards specified for Class 1E components. The CRCW system provides cooling water at approximately 40°F during normal operation and in the event of accidents or transients. The CRCW system normally uses water from the non-safety-related plant service water system (PSWS) to cool the refrigeration condensers. In the event the PSWS becomes inoperative, the condensers are automatically cooled by the safety-related shutdown service water system (SSWS) (for further details of this system refer to Section 9.2.1 of the SER).

The CRCW system comprises two separate trains, each powered from an independent Class 1E electrical system. Each train consists of a chilled water pump, a separate refrigeration unit, chilled water coils, chilled water compression tanks, and associated piping, valves, and instrumentation. A single failure may cause the loss of a single train but the remaining train is of sufficient capacity to maintain cooling of the control room and adjacent areas, thus complying with the single-failure criterion. The CRW system is protected against external floods and tornado missiles. It is also protected against the effects of seismic events because it is designed as a seismic Category I system in accordance with the requirements of Regulatory Guide (RG) 1.29, "Seismic Design Classification." The CRCW system, therefore, complies with the criteria of GDC 2, "Design Bases for Protection Against Natural Phenomena." The CRCW system is also protected against the effects of internally generated missiles and against the effects of piping failures, thus complying with the requirements of GDC 4, "Environmental and Missile Design Bases." The CRCW system is not shared with another unit, thus complying with the criteria of GDC 5, "Sharing of Structures, Systems, and Components."

The CRCW system receives heat from the control room HVAC system and transfers it to the plant service water system (PSWS) or shutdown service water system (SSWS). Both of these systems, in turn, transfer the heat absorbed to the ultimate heat sink, thus complying with the criteria of GDC 44, "Cooling Water," of Appendix A to 10 CFR 50.

The applicant has stated that the CRCW system equipment was inspected and tested at the factory. Controls, interlocks, and safety devices were checked, adjusted, and tested to ensure satisfactory operation. The applicant periodically monitors the suction and condensing pressures of the refrigeration units, the lubricant pressure for the compressors, and the differential water pressure across the condensers and evaporators of each refrigeration unit, thus complying with the criteria of GDC 45, "Inspection of Cooling Water System," and GDC 46, "Testing of Cooling Water System," of Appendix A to 10 CFR 50. Therefore, the staff finds that the design of the CRCW system is acceptable.

9.2.8.2 Plant Chilled Water System

There is no specific section of the Standard Review Plan (SRP) that provides guidelines for the review of the plant chilled water (PCW) system. Therefore, SRP Section 9.2.2, "Reactor Auxiliary Cooling Water Systems," was used as a guide for the review of this system.

The PCW system is not required for plant shutdown or for the mitigation of transients or accidents and, therefore, is not designed to the standards required for safety-related equipment. It is designed to provide chilled water to the

drywell, containment building, turbine building, radwaste building, fuel building, and control building. The piping components are seismically supported in some areas of seismic Category I buildings in order to prevent damaging safety-related equipment as a result of a seismic event, thereby complying with Position C.2 of RG 1.29, "Seismic Design Classification." Safety-related equipment is protected against flooding resulting from a break in the PCW system. The PCW system, therefore, complies with the criteria of GDC 2, "Design Bases for Protection Against Natural Phenomena," and GDC 4, "Environmental and Missile Design Bases."

The PCW system contains five water-cooled centrifugal chiller/pump combinations; one of these remains on standby while the others are in operation. The plant service water system is used to cool the PCW system chiller condensers. The temperature of the water leaving each chiller is controlled to a maximum of 45 ± 2°F when the plant service water (PSW) temperature is 95°F and 40°F when the PSW water is below 90°F.

A chiller is shut down if plant service water pressure at the inlet to any operating chiller is lost.

Therefore, the staff finds that the design of the plant chilled water system is acceptable.

9.2.8.3 Service Building Chilled Water System

There is no specific section of the Standard Review Plan (SRP) that provides guidelines for the review of the service building chilled water (SBCW) system. Therefore, SRP Section 9.2.2, "Reactor Auxiliary Cooling Water Systems," was used as a guide for the review of this system.

The SBCW system provides chilled water to the service building HVAC system. It operates only during normal plant operating conditions and is not required for plant shutdown nor for the mitigation of transients or accidents and is not designed to the standards required for safety-related systems.

The SBCW system uses plant service water, at a maximum temperature of 95°F, to cool the SBCW refrigeration condensers. It supplies water, at a maximum temperature of 45°F, to the air handling units in the service building. A break in the SBCW system will not adversely affect any safety-related equipment because of flooding of adjacent areas. Since the service building contains no safety-related equipment, other failures of the SBCW system will not affect safe plant shutdown or the mitigation of transients or accidents, thus complying with the criteria of GDC 4, "Environmental and Missile Design Bases." Therefore, the staff finds that the design of the SBCW system is acceptable.

9.3 Process Auxiliaries

9.3.3 Standby Liquid Control System

The heat tracing which heretofore has been utilized to maintain the temperature of the boron solution in the pipelines of the standby liquid control system (SLCS) has been removed. This requirement for heat tracing, is considered to be unnecessary because the temperature in the building in which the SLCS is maintained is sufficient to prevent the precipitation of sodium pentaborate from the solution in the pipelines. In lieu of heat tracing, the applicant must

monitor the pump suction pipe temperatures in order to ensure against such precipitation. The Technical Specifications will reflect this requirement.

The applicant has reported that the SLCS is now designed to inject the sodium pentaborate solution via the high-pressure core spray sparger in order to provide better mixing of the solution in the reactor coolant system than would have otherwise been possible when using the SLCS sparger near the bottom of the core. The SLCS sparger is locked out of service but may be used as an alternate path by opening the SLCS manual injection valve.

The staff finds these revisions to be acceptable.

9.3.5 Postaccident Sampling Capability (NUREG-0737, Item II.B.3)

In the Clinton SSER 5 the staff reviewed the applicant's postaccident sampling system (PASS) and concluded that the PASS meets the requirements of Item II.B.3 of NUREG-0737. By letter dated May 5, 1986, the applicant provided a revision to the PASS evaluation report which affects, in various ways, 5 of the 11 criteria of Item II.B.3 as reported in SSER 5. The revised evaluation is presented below.

Criterion (5)

> The time for a chloride analysis to be performed is dependent upon two factors: (a) if the plant's coolant water is sea water or brackish water and (b) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions the applicant shall provide for a chloride analysis within 24 hours of the sample being taken. For all other cases, the applicant shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done on site.

Chloride analysis is to be performed on a undiluted reactor coolant sample within 96 hours of sampling. A reactor coolant sample may be analyzed on site by using an ion chromatograph if the sample activity is less than one one-thousandth of the worst case activity. If chlorides exceed 0.15 ppm, the dissolved oxygen can be verified to be less than 0.1 ppm. These provision meet Criterion (5) and are, therefore, acceptable.

Criterion (7)

> The analysis of primary coolant samples for boron is required for pressurized-water reactors (PWRs). (Note that Revision 2 of Regulatory Guide 1.97 specifies the need for primary coolant boron analysis capability at BWR plants.)

A diluted grab sample of the reactor coolant will be analyzed for boron by use of a tetrafluoraborate selective ion electrode in the range of 500-6000 ppm with an accuracy of 10%. This provision meets the recommendations of Regulatory Guide 1.97, Revision 3 and Criterion (7) and is, therefore, acceptable.

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Criterion (8)

> If in-line monitoring is used for any sampling and analytical capability specified herein, the licensee shall provide backup sampling through grab samples, and shall demonstrate the capability of analyzing the sample. Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per week until the accident condition no longer exists.

In-line monitoring is to be used to determine containment atmosphere hydrogen and oxygen levels and reactor coolant dissolved hydrogen and oxygen, pH, and conductivity. The PASS can obtain both diluted and undiluted reactor coolant, dissolved gas and containment atmosphere samples for either onsite or offsite analyses. Prior arrangements have been made for a shipping container and for an offsite facility for sample analysis. The staff finds these provisions meet Criterion (8) and are, therefore, acceptable.

Criterion (10)

> Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the reactor coolant systems.

The accuracy, range, and sensitivity of the PASS instruments and analytical procedures are consistent with the recommendations of Regulatory Guide 1.97, Revision 3, and the July 27, 1983, clarifications of NUREG-0737, Item II.B.3, "Post-Accident Sampling Capability." Therefore, they are adequate for describing the radiological and chemical status of the reactor coolant. The analytical methods and instrumentation were selected and evaluated for their ability to operate in the postaccident sampling environment.

Technician requalification training will occur every 2 years, as a minimum. Refresher training of technicians will occur on a semiannual basis through the use of PASS for routine analyses and drills. Analytical and sampling instrumentation are to be calibrated routinely as prescribed in the vendor manual. The staff determined that these provisions meet Criterion (10) of Item II.B.3 in NUREG-0737, and are, therefore, acceptable.

Criterion (11)

> In the design of the postaccident sampling and analysis capability, consideration should be given to the following items:
>
> (a) Provisions should be made for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the RCS or containment, for appropriate disposal of the samples, and for flow restrictions to limit reactor coolant loss from a rupture of the sample line. The postaccident reactor coolant and containment atmosphere samples should be representative of the reactor coolant in the core area and the containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from

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containment. The residues of sample collection should be returned to containment or to a closed system.

(b) The ventilation exhaust from the sampling station should be filtered with charcoal absorbers and high-efficiency particulate air (HEPA) filters.

The applicant has addressed provisions for purging and recirculation back to containment to ensure samples are representative, and the small size of the sample line serves to limit reactor coolant loss from a rupture of the sample line. To limit iodine plateout, the containment atmosphere sample line is heat traced. The PASS panel effluents are routed through the auxiliary building HVAC during normal operation, and through the drywell purge system for accidents. The drywell purge system contains charcoal absorbers and HEPA filters. Samples will be obtained from the jet pump instrumentation system when the reactor coolant system is at pressure to obtain a representative sample under accident conditions.

At power levels of less than 1%, a sample that is representative of core conditions would be obtained after increasing the reactor water level by 18 inches. This will fully flood the standpipes of the moisture separators and will provide a thermally induced recirculation flow path for mixing, thereby ensuring a representative sample from the core.

A single sample line is also connected to both loops in the residual heat removal (RHR) system. This provides a means of obtaining a reactor coolant sample when the reactor is depressurized and at least one of the RHR loops is operated in the shutdown cooling mode. Similarly, a suppression pool liquid sample can be obtained from the RHR loop lined up in the suppression pool cooling mode.

The staff has determined that these provisions meet Criterion (11) of Item II.B.3 of NUREG-0737 and are, therefore, acceptable.

On the basis of the above evaluation, the staff concludes that the postaccident sampling system meets the requirements of Item II.B.3 of NUREG-0737 and is, therefore, acceptable.

9.4 Ventilation Systems

9.4.5 Engineered Safety Features Ventilation System

The SER for the Clinton Power Station noted that the fan coiling units for the combustible gas control system (CGCS) are automatically started either when the respective CGCS trains start or when the cubicle temperature exceeds 120°F. The Clinton FSAR, through Amendment 38, does not mention automatic initiation of the CGCS cubicle cooling units.

The applicant has reported to the staff that the temperature limit switch has been removed and CGCG room coolers now operate continuously. The staff finds this change acceptable.

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9.4.6 Machine Shop Area HVAC System

There is no specific section of the Standard Review Plan (SRP) that provides guidelines for the review of the machine shop area HVAC system. Therefore, SRP Section 9.4 4, "Turbine Area Ventilation System," was used as a guide for the review of this system.

The machine shop area HVAC system serves all areas of the machine shop during normal operation. It is not designed to aid in plant shutdown nor to mitigate transients or accidents. Thus, the system is not safety related and is not designed in accordance with the standards specified for safety-related systems.

The machine shop HVAC system is designed to limit the temperature in the machine shop to a maximum of 104°F and to maintain the temperature in equipment areas to that required by the equipment. The system provides some filtered outdoor air to purge the machine shop area of any unpleasant or harmful atmosphere. Potentially contaminated areas are maintained at a slightly lower pressure than the surrounding clean areas, in order to maintain a flow of clean air into the potentially contaminated areas before filtering and subsequent exhaust. Clean air, from the machine shop cold tools room and the lavatories, is routed directly to the exhaust. Potentially contaminated air, from the equipment decontamination room, hot tools room, and weld shop is passed through prefilters and high-efficiency particulate air (HEPA) filters before being exhausted. Air coming directly from machinery passes through moisture separators, prefilters, and HEPA filters before being exhausted to the environment. Pressure control dampers between clean and potentially contaminated areas close on backflow and fail in the closed position. In this way, contaminated air is prevented from entering uncontaminated spaces. Thus the machine shop area HVAC system complies with the criteria of GDC 60, "Control of Releases of Radioactive Materials to the Environment."

Failure of the machine shop area HVAC system will not affect any safety-related components. Therefore, the staff finds that the design of the machine shop area HVAC system is acceptable.

9.4.7 Circulating Water Screenhouse Ventilation System

There is no specific section of the Standard Review Plan (SRP) that provides guidelines for the review of the circulating water screenhouse ventilation (CWSHV) system. Therefore, SRP Section 9.4.4, "Turbine Area Ventilation System" was used as a guide for the review of this system.

The CWSHV system serves all areas of the circulating water screenhouse. It is not required for plant shutdown nor is it required for the mitigation of transients or accidents. Therefore, it is not safety related and is not designed in accordance with the standards specified for a safety-related system.

The CWSHV system is designed to limit the screenhouse temperature to a maximum of 122°F. A portion of the air in the circulating water screenhouse is passed through the chlorinator room before being exhausted to the atmosphere. When a fire pump is operating, the fire pump room exhaust fans are designed to limit the fire pump room temperature to 122°F. The chlorinator room is maintained at a slightly lower pressure than the screenhouse with air flowing from the screenhouse to the chlorinator before being exhausted. In addition, there is a

pressure control damper between the screenhouse and chlorinator of the backflow type to minimize the flow of air to the screenhouse from the chlorinator room.

A failure of a CWSHV system fan cannot damage safety-related equipment, and the system, therefore, complies with GDC 4, "Environmental and Missile Design Bases." Therefore, the staff finds that the design of the CWSHV system is acceptable.

9.4.8 Laboratory HVAC System

There is no specific section of the Standard Review Plan (SRP) that provides guidelines for the review of the laboratory HVAC system. Therefore, SRP Section 9.4.4, "Turbine Area Ventilation System" was used as a guide for the review of this system.

The laboratory HVAC system is designed to maintain environmental conditions suitable for personnel and equipment in the laboratory area, laundry area, bioassay area, and counting room. It is not required for plant shutdown nor for the mitigation of transients or accidents. Therefore, the system is not safety related and is not designed in accordance with the standards specified for safety-related systems.

The laboratory HVAC system is designed to maintain the following conditions in the laboratory and laundry areas:

Area	Relative humidity, %	Temperature, °F
Laboratory	45 ± 5	75 ± 1
Washer dryer		104 max
Laundry dry	50 ± 10	75 ± 5

The laboratory HVAC system draws outside air into the system through an air intake louver. The air is then filtered, heated or cooled as necessary, and blown through the two HVAC trains by means of two 50% capacity makeup fans. Most of the outside air (23,075 cfm of 32,650 cfm) passes into the two trains of the laboratory HVAC system while the rest (9575 cfm) passes into hoods in the radiation chemistry laboratory.

The laboratory HVAC air is exhausted through a lint filter and two filter packages consisting of a prefilter, a HEPA filter, and two 50% capacity centrifugal fans.

The counting room system has a separate HVAC system which consists of an outside air intake, and two separate 100% intake trains. Each intake train contains a prefilter, a HEPA filter, an electric heating coil, and a 100% capacity fan. The exhaust train contains two 100% exhaust fans, in parallel.

The laboratory air and counting room air is exhausted to the atmosphere through a common plant HVAC vent. The laboratory HVAC system (including the counting room HVAC system) cannot affect any safety-related system in the event of system failure from a tornado or earthquake, thus complying with the criteria of GDC 2, "Design Bases for Protection Against Natural Phenomena," nor can any safety-related system be affected as a result of missiles generated by the laboratory system, thus complying with the criteria of GDC 4, "Environmental and Missile Design Bases."

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The laundry rooms, high-level laboratory, and radiation chemistry laboratory are set at slightly lower pressure with respect to the surrounding areas in order to prevent potential flow of contaminated air into clean air spaces. This condition, together with the use of HEPA filters to capture potentially radioactive particulate matter, complies with the criteria of GDC 60, "Control of Releases of Radioactive Materials to the Environment."

Therefore, the staff finds that the design of the laboratory HVAC system is acceptable.

9.4.9 Service Building HVAC System

There is no specific section of the Standard Review Plan (SRP) that provides guidelines for the review of the service building HVAC (SBHVAC) system. Therefore, SRP Section 9.4.4, "Turbine Area Ventilation System" was used as a guide for the review of this system.

The SBHVAC system is designed to maintain an environment suitable for personnel in the service building. Offices are maintained at a temperature of 75 ± 2°F with a relative humidity of 45 ± 5% in the summer, 35 ± 5% in the winter. It is not required for plant shutdown, nor for the mitigation of transients or accidents and thus is not safety related. Therefore, the SBHVAC system is not designed in accordance with the standards specified for a safety-related system.

The SBHVAC system consists of four subsystems, serving the following areas:

- The service building exterior zone HVAC system serves exterior offices and classrooms on the first and second floors of the service building.
- The service building interior Zone 1 HVAC system serves first floor interior spaces, the second floor vault, and the air conditioned basement areas.
- The service building interior Zone 2 HVAC system serves second floor interior spaces.
- The contractor's locker room HVAC system serves the first floor contractor's locker room.

All four subsystems contain outside air louvers, supply air filters, and a return air fan. The first three subsystems contain a blowthrough air handling unit, and the locker room HVAC air handling unit is the drawthrough type. Each of the first three subsystems has, in addition, a mixing plenum, a hot air duct, and a cold air duct. Each subsystem air handling unit contains a fan, an electric heating coil, and a chilled water cooling coil.

The service building is maintained at a pressure slightly higher than the surroundings in order to prevent infiltration.

The SBHVAC system does not contain any radioactive material and, thus, the criteria of GDC 60, "Control of Releases of Radioactive Materials to the Environment" are not applicable. The service building does not contain any safety-related systems and, therefore, cannot damage any safety-related system because of failure of any of the subsystems. Thus, the criteria of GDC 2, "Design Bases for Protection Against Natural Phenomena," and GDC 4, "Environmental and Missile

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Design Bases," are not applicable. Therefore, the staff finds that the design of the SBHVAC system is acceptable.

9.4.10 Radwaste Building Area Ventilation System

There is no specific section of the Standard Review Plan (SRP) that provides guidelines for the review of the radwaste building area ventilation (RBAV) system. Therefore, SRP Section 9.4.4, "Turbine Area Ventilation System" was used as a guide for the review of this system.

The RBAV system provides ventilation to all parts of the radwaste building except for the machine shop. It is required to work during normal operation but is not required for plant shutdown or for the mitigation of transients or accidents. Therefore, the RBAV system is not safety related, and thus, is not designed in accordance with the standards specified for a safety-related system. Safety-related systems are protected from the effects of missiles resulting from fan failure in the RBAV system.

Other failures of the RBAV system will not affect any safety-related system since the radwaste building does not contain any safety-related equipment.

The RBAV system consists of outside air intake filters, a heating coil, a cooling coil, two 100% capacity supply air fans, and supply air ductwork. It maintains the radwaste monitoring areas at a temperature of 73°F. A slightly positive pressure is maintained in the radwaste operations area with respect to surrounding areas to prevent the infiltration of potentially contaminated air.

One of the two 100% capacity exhaust fans draws air from potentially contaminated areas through prefilters and HEPA filters before discharging this air to the common HVAC vent. A negative pressure differential of 0.25 inch, w.g., with respect to the surroundings, is maintained in the radwaste building (with the exception of the machine shop and storeroom area which are maintained at negative pressures of 0.125 inch w.g. and 0.100 inch w.g., respectively). The RBAV system has fan coil units located in some areas to maintain temperatures within certain limits. Each fan coil unit consists of a fan and cooling coil in a sheet metal housing. Supply air ducts are provided as necessary. Chilled water is circulated through the center ventilation coil to provide cooling for the supply air system. In this way the RBAV system complies with the criteria of GDC 60, "Control of Released of Radioactive Material to the Environment." The staff finds that the design of the radwaste building area ventilation system is acceptable.

9.5 Fire Protection System

Supplement 5 to the Clinton Power Station Safety Evaluation Report (SSER 5) included five open items relative to fire protection. By letters dated October 25, November 1, December 6, December 10, and December 11, 1985; and February 13, February 17, March 4, March 7, March 19, April 14, May 29, and June 19, 1986, the applicant provided additional information, including Amendment 1 to the Clinton Fire Protection Evaluation Report (FPER), Amendment 1 to the Fire Protection Safe Shutdown Analysis (SSA), and requests for approval of additional

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deviations from staff fire protection guidelines of Appendix A to Branch Technical Position (BTP) APCSB 9.5-1 and Appendix R to 10 CFR 50.* The staff's evaluation of these submittals and of the Final Safety Analysis Report (FSAR) for Clinton through Amendment 38 are included in this SSER.

Amendments 1 to the FPER and SSA and the FSAR amendments contain changes resulting from continued program development and the applicant's reexamination of Appendix R safe shutdown capabilities and incorporated information previously provided via docketed correspondence, editorial changes, and clarifications. Only those changes that affect the staff's previous safety evaluations are addressed in this SSER.

Generic Letter 86-10 states that inclusion of the fire protection program into the FSAR is a prerequisite for licensing for all applications now under review. By FSAR Amendment 38, the applicant incorporated the fire protection program that has been approved by the staff, including the fire hazards analysis and major commitments that form the basis of the fire protection program, into the FSAR by reference to specific previous submittals. This is in accordance with Generic Letter 86-10 and is, therefore, acceptable.

By letter dated June 19, 1986, the applicant also submitted an exhaustive fire zone by fire zone National Fire Protection Association (NFPA) code compliance evaluation report. The scope of the evaluation was to review each fire protection feature at Clinton and to evaluate its level of compliance with the applicable sections of the NFPA code to which the applicant committed to meet. Automatic detection systems, manual and automatic fire suppression systems, fire doors and dampers, hose stations, portable fire extinguishers, exterior hydrants, fire pumps, and other fire protection features were included in the review. The review covered the design, installation, and maintenance of the fire protection features. The staff audited the subject compliance evaluation report and did not identify any deviations from the NFPA codes that are inconsistent with conditions that have been reviewed and approved by the staff in the Clinton SER and its supplements, or that adversely affect the level of fire safety at the station.

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*The technical requirements of Appendix R to 10 CFR 50 apply to licensed nuclear power electric generating plants that were operating before January 1, 1979, and therefore do not apply to Clinton. However, on May 23, 1980, the Commission issued a Memorandum and Order (CLI-80-21) that stated that the combination of the guidance contained in Appendix A to BTP APCSB 9.5-1 and the technical requirements set forth in Appendix R to 10 CFR 50 define the essential elements for an acceptable fire protection program at nuclear power plants docketed for construction permits before July 1, 1976, for demonstration of compliance with GDC 3 of Appendix A to 10 CFR 50. Therefore, the staff has used the technical requirements of Appendix R to 10 CFR 50 and Appendix A to BTP APCSB 9.5-1 as guidelines in its evaluation of the applicant's fire protection program for Clinton. SRP Section 9.5.1, "Fire Protection Program," contained (in BTP 9.5.1, dated July 1981) the guidelines of Appendix A to BTP APCSB 9.5-1, and the technical requirements of Appendix R to 10 CFR 50. BTP CMEB 9.5-1 also presents guidelines acceptable for development of a fire protection program. Therefore, the guidelines of BTP CMEB 9.5-1 are also referenced in this SSER.

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9.5.1 Description and Evaluation

9.5.1.1 Water Supply Systems

In the Clinton SER, the staff stated that the underground loop is constructed of 14-inch-diameter pipe. In FSAR Amendment 36, the applicant stated that the underground loop is constructed of 12-inch and 14-inch diameter pipe. This change does not affect the staff's evaluation of the water supply system at Clinton.

In the Clinton SER, the staff stated that yard hydrants are provided at intervals of 250 feet in accordance with Section E.2 of Appendix A to BTP APCSB 9.5-1. During the plant site audit of the applicant's fire protection program for Clinton, the staff observed that fire hydrant spacing exceeded 250 feet within the power block. By letter dated March 7, 1986, the applicant stated that the yard hydrants are installed at intervals of about 325 feet. This spacing does not meet staff guidelines. However, the applicant stated that additional hose lengths will be provided so that the installations will meet NFPA 24 and that the fire brigade will be trained to handle the size and lengths of hose provided. On the basis of the applicant's commitments, the staff finds that the existing yard hydrant spacing meets the intent of Section E.2 of Appendix A to BTP APCSB 9.5-1 and is, therefore, acceptable.

Also during the plant site audit, the staff could not ascertain the locations of the fire pump flow meter discharge outlets relative to the pump intakes and, therefore, expressed concern that improper location could adversely affect the fire pump flow test results. By letter dated March 7, 1986, the applicant informed the staff that the vertical distance between the pump intake and discharge outlets is about 32 feet and the horizontal distance is about 6 feet, which meets NFPA 20. The applicant also committed to check the preoperational flow test results against the baseline to determine if there are any adverse effects. On these bases, the staff finds this issue resolved.

9.5.1.2 Sprinkler and Standpipe Systems

During the plant site audit of the applicant's fire protection program for Clinton, the staff observed that in many safety-related areas it was not possible to reach all locations with 75 feet of fire hose in accordance with Section E.3.(d) of Appendix A to BTP APCSB 9.5-1. By letter dated March 7, 1986, the applicant stated that the following corrective actions were taken to resolve the staff's concern: hose was replaced with proper length of hose, hose stations were relocated, and additional hose stations were installed. The applicant also stated that with three exceptions (the drywell, the control room, and the main steam tunnel), a maximum of 100 feet of hose will be provided for each hose connection. The use of 100 feet of hose meets Section C.6.c.(4) of BTP CMEB 9.5-1 and is, therefore, acceptable. For the drywell, the control room, and the steam tunnel, additional hose will be available, if needed, to ensure full hose stream coverage. The plant water distribution system is capable of supplying these hose stations with adequate quantity of water and pressure through the hose lengths required. In addition, sufficient space is available in each of these locations for accessibility and to ensure that the hose can be used. The staff concludes, therefore, that the use of more than 75 feet of hose in the drywell, control room, and main steam tunnel is an acceptable deviation from Section E.3.(d) of Appendix A to BTP APCSB 9.5-1.

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During the plant site audit, the staff also expressed concern that all cable trays located outside the cable spreading room were not protected by automatic sprinkler systems in accordance with Section D.3.(c) of Appendix A to BTP APCSB 9.5-1. By letter dated March 7, 1986, the applicant provided an analysis of the plant areas containing concentrations of cables and cable trays. Automatic sprinkler systems have been installed in the zones delineated in the SSA and FPER.

On the basis of its review of the SSA, FPER, and the cable tray analysis, the staff concludes that cable tray protection meets the intent of Section C.5.e of BTP CMEB 9.5-1, and is, therefore, acceptable.

9.5.1.4 Fire Detection Systems

In the Clinton FSAR, the applicant committed to provide automatic fire detection in all plant areas containing safety-related equipment., In the SSA, the applicant identified the fire areas that lack areawide fire detection and requested staff approval of deviations from Section III.F of Appendix R to 10 CFR 50 to the extent that it states that automatic fire detection systems should be installed in all areas of the plant that contain safety-related systems.

In SSER 5, the staff approved deviations from Section III.F of Appendix R to 10 CFR 50 for Fire Zones A-1e, A-2b, A-2d, A-2f, A-2g, A-2h, A-2i, A-2j, A-3a, A-3c, CB-1a, CB-1b, CB-5b, F-1h, F-1i, F-1k, and M-2c and for Fire Areas D-7, D-8, and D-9. Also, in SSER 5, the staff denied deviations from Section III.F of Appendix R to 10 CFR 50 for Fire Zones A-2e, CB-1d, D-4b, D-5b, D-6b, F-1a, F-1m, and F-1n, and for Fire Areas C-1, D-1, D-2, and D-3, and stated that deviations are not required for Fire Zones D-4a, D-5a, and D-6a.

In Amendment 1 to the SSA, the applicant withdrew its deviation requests for Fire Zones D-4a, D-4b, D-5a, D-5b, D-6a, D-6b, F-1a, and F-1m and Fire Areas D-1, D-2, and D-3; provided additional information on Fire Zones A-2e, CB-1d, and F-1n, and Fire Area C-1; and requested approval of additional deviations from Section III.F of Appendix R to 10 CFR 50 for Fire Zones A-1c, A-1d, CB-1h, CB-1i, F-1c, F-1d, F-1e, F-1f, F-1g, F-1j, and F-1o and for Fire Areas C-2, CB-7, and D-10 (Unit 2 diesel generator ventilation air intake rooms), and T-1.

The staff's evaluation of the applicant's deviation request for Fire Area C-1 is in Section 9.5.5 of this SSER.

Fire Zones A-1c, A-1d, CB-1h, F-1c, F-1d, F-1e, F-1f, F-1j, F-1k, and F-1o and the three rooms that were included for the Unit 2 diesel generator ventilation air intake rooms in Fire Area D-10 do not contain safe-shutdown or safety-related equipment or cables, but are surrounded by or are adjacent to fire zones that are equipped with fire detectors. If a fire were to occur in any of these locations, it would be detected by detectors located in adjoining zones, or by plant operators who would summon the plant fire brigade. Because these location do not contain safe-shutdown or safety-related components, the staff does not expect a loss of a safety function as a result of fire in any of these locations. The staff concludes, therefore, that the absence of fire detectors in Fire Zones A-1c, A-1d, CB-1h, F-1c, F-1d, F-1e, F-1f, F-1j, and F-1o and Fire Area D-10, is an acceptable deviation from Section III.F of Appendix R to 10 CFR 50.

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Fire Zones A-2e, F-1g, and F-1n contain safe-shutdown components. However, because the combustible fuel load in each zone is negligible, the staff does not expect a fire of significant magnitude or duration to occur. If a fire should occur, it would be detected by fire detectors located in adjoining zones and extinguished by the plant fire brigade. On the basis of its review and the ability to achieve safe shutdown following a fire, the staff concludes that the installation of fire detectors in Fire Zones A-2e, F-1g, or F-1n would not significantly increase the level of fire safety. The lack of fire detectors in Fire Zones A-2e, F-1g, and F-1n is, therefore, an acceptable deviation from Section III.F of Appendix R to 10 CFR 50.

Fire Zone CB-1d, which consists of the radiation-chemistry laboratory area, contains a Division 2 cable tray riser. This cable riser is separated from the laboratory area by 2-hour fire rated barriers and from the Division 1 safe shutdown cables (located in Fire Zone CB-1e) by more than 50 feet. The maximum fire severity in the laboratory area is less than 30 minutes. Partial fire detection is provided in Fire Zone CB-1d and the Division 1 cables are protected by an automatic fire suppression system. The laboratory area is constantly manned. Because Fire Zone CB-1d is constantly occupied and is provided with a partial fire detection system, the staff has reasonable assurance that a fire in the laboratory area will be detected during its incipient stage and will be promptly extinguished. Moreover, because the Division 1 cables are separated from the laboratory by fire barriers having a fire resistance rating greater than the maximum fire severity, the staff has further assurance that a fire in the laboratory area will not threaten the cables. Finally, because of the spatial separation between the redundant cables and because one division is protected by an automatic suppression system, the staff has reasonable assurance that a fire in the laboratory would not pose a credible threat to the plant's ability to achieve and maintain safe shutdown. On the basis of this evaluation, the staff concludes that the absence of fire detectors throughout Fire Zone CB-1d is an acceptable deviation from Section III.F of Appendix R to 10 CFR 50.

Fire Zone CB-1i contains the Divisions 1 and 2 control room air handling units, control room chillers, control room air filter packages and fans, Division 1 and 2 electrical cables and trays, unit substations, and motor control centers and panels, which are safety related. This zone also contains cables and equipment belonging to both methods of safe shutdown. To ensure safe shutdown, safe shutdown cables have been rerouted and the missile wall separating the zone has been upgraded to a 3-hour fire rated barrier. Automatic fire detection is provided for all significant fire hazards in the zone, and the air filter packages are protected by manual deluge sprinkler systems. Combustible materials in this zone occur in limited quantities and are widely dispersed. Consequently, the staff does not expect a fire of significant magnitude or duration to occur. If a fire should occur, it would be detected by fire detectors in the zone, and, in the staff's opinion, should be extinguished before threatening the safe-shutdown capability of the plant. On the basis of the above evaluation, the staff concludes that the installation of additional fire detectors in Fire Zone CB-1i would not significantly increase the level of fire safety. Therefore, the omission of an areawide fire detection system is an acceptable deviation from Section III.F of Appendix R to 10 CFR 50.

Fire Area CB-7 is a stairwell tower that is enclosed by 2-hour fire rated walls and a corridor at elevation 801 feet 9 inches that is enclosed by 3-hour fire rated walls. This area contains safety-related equipment, but does not contain

any equipment required for safe shutdown. A fire detection system is installed at the stairwell landings at elevations 781 feet 0 inch and 800 feet 0 inch and in the corridor at elevation 801 feet 9 inches. Fire detectors are not installed in the lower elevation landings of the stairwell. The most significant fuel load in the area is the result of cable insulation from balance of plant (BOP) cables located at elevation 800 feet 0 inch. Except for the BOP cables, there are few combustibles in Fire Area CB-7. Consequently, the staff does not expect a fire of significant magnitude or duration to occur. If a fire should occur in the lower elevations of the fire area, it would be detected with only minimal delay by the detectors located in the upper elevations of the fire area. In the event of a fire involving the BOP cables, the staff does not expect a delay in detecting the fire because the cables are located in an area that is provided with detectors. Moreover, because the area does not contain any safe-shutdown components and is separated from all areas containing safe-shutdown components, the staff does not expect loss of safe-shutdown capability to result from a fire in Fire Area CB-7. On the basis of its evaluation, the staff concludes that the installation of additional fire detectors in Fire Area CB-7 would not significantly increase the level of fire safety. The omission of an areawide fire detection system is, therefore, an acceptable deviation from Section III.F of Appendix R to 10 CFR 50.

The turbine building is a single fire area (Fire Area T-1). With the exception of the main steam tunnel, which is discussed in Section 9.5.2.1 of this report, the turbine building is separated from all safety-related buildings by 3-hour fire rated barriers. The building is classified as a non-safety-related non-seismic building, although it contains some Class 1E cables and instrumentation devices. There is no safe-shutdown equipment located in the building. The significant fire hazards located in the building (e.g., main generator exciter, turbine oil reservoir tank, hydrogen seal oil unit, and the area beneath the turbine generator) are protected by automatic fire suppression systems. Because the turbine building does not contain any safe-shutdown components, the staff has reasonable assurance that in the event of a fire within the building safe shutdown of the plant will not be affected. In addition, because of the perimeter construction and because each significant fire hazard in the building is protected by an automatic fire suppression system suited to the hazard, the staff believes that any fire within the building will not threaten adjacent safety-related systems. Furthermore, the applicant stated that if the cables and devices in the turbine building failed as a result of fire exposure, other parameters, which are not measured in the turbine building, are available. On the basis of this review, the staff concludes that the installation of an areawide fire detection system in the turbine building would not significantly increase the level of fire safety. This is, therefore, an acceptable deviation from Section III.F of Appendix R to 10 CFR 50.

Fire Area C-2 consists of the containment building. Redundant safe-shutdown divisions in this area are separated in accordance with Section III.G of Appendix R to 10 CFR 50. An areawide fire detection system has not been provided. However, linear thermal detectors have been installed in all cable trays containing safe-shutdown cables and in all safety-related cable trays with more than 40% fill. On the basis of its review of the applicant's FPER and SSA, the staff has concluded that fire detectors have been provided on the basis of specific identified hazards in Fire Area C-2 in accordance with Section F.1 of Appendix A to BTP APCSB 9.5-1 and are, therefore, acceptable.

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9.5.2 Other Items Related to Fire Protection

9.5.2.1 Fire Barriers and Penetrations

During the plant site audit of the applicant's fire protection program for Clinton, the staff observed that control building Fire Areas CB-1, CB-2, CB-3, CB-4, CB-5, and CB-7 were bounded in full or in part by 8-inch-thick hollow concrete block walls. During the audit, the applicant informed the staff that it had attributed a 2-hour fire resistance rating to the walls. The staff had two concerns. First, that fire test results were not available to substantiate the fire resistance rating of the walls and second, that staff guidelines of Appendix A to BTP APCSB 9.5-1 state that the walls in question should have a fire resistance rating of 3 hours.

By letter dated December 11, 1985, the applicant submitted documentation intended to substantiate the fire resistance rating of the block walls and, in SSA Amendment 1, requested a deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1 to the extent that it states that walls enclosing separate fire areas should have a minimum fire rating of 3 hours for the block walls separating these control building fire areas. The documentation showed that the fire resistance rating of hollow concrete block walls can be estimated by an analytical method based on the aggregate type used in the block units, and the equivalent solid thicknesses of the wall. The staff has reviewed the applicant's submittal and concurs with the applicant's statement that a nominal fire resistance rating of 2 hours can be attributed to the 8-inch-thick hollow concrete block walls installed at Clinton.

The control building fire areas bounded by hollow concrete block walls include the Divisions 1 and 2 cable spreading rooms, auxiliary electric equipment rooms, battery rooms, switchgear rooms, cable risers, a stairwell tower, and access areas. Each of the affected fire zones, except for Fire Zones CB-1h and CB-5b, which have negligible fuel loads, is equipped with an automatic fire detection system. The estimated fire resistance rating of the hollow concrete block walls is greater than the estimated equivalent fire severity in each fire area and zone, except for the cable spreading rooms, the auxiliary electric equipment room, and the cable riser. For each of these, an automatic sprinkler system has been provided.

The staff was concerned that the degree of fire protection offered by the subject barriers would not be adequate to prevent the spread of fire from one area to another. The combustible loading in the subject areas consists primarily of electrical cable insulation. These cables are qualified to IEEE Standard 383-1974. In view of the inherent ignition and flame spread resistance properties of IEEE Std. 383-qualified cables, and because each of the subject areas is equipped with smoke detectors, the staff expects that any postulated fire would be detected during its early development stages and that appropriate fire brigade action would be initiated well before the structural integrity of the fire barriers is adversely affected. Moreover, in the event that fire brigade response is delayed in those areas where the severity and duration of anticipated fires, in terms of material available to burn, is less than the estimated fire resistance rating of the barriers enclosing the area, the staff expects the barriers to withstand the hazards associated with the area. For those areas in which the estimated fire severities exceed the estimated fire resistance rating of the barriers enclosing the area, automatic sprinkler systems have

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been provided. In the event of a fire in one of these areas, the staff expects the sprinkler system to operate and control the fire until fire brigade action is initiated. In the staff's opinion, the sprinklers will provide adequate protection for the barriers until the fire is extinguished. It is the staff's judgment that with the detection and suppression provided, each of the subject fire areas is sufficiently bounded to withstand the hazards associated with the area and, as necessary, to protect the area from a fire outside the area. On these bases, the staff concludes that the 8-inch-thick hollow concrete block walls, with the fire protection provided, are adequate fire barriers for the fire areas listed in SSA Amendment 1 and are, therefore, acceptable.

The turbine building (Fire Area T-1) is separated from the auxiliary building by 3-hour fire rated barriers except at elevation 755 feet 0 inch where the main steam and feedwater lines pass between the buildings. At this location, a non-fire-rated steel wall separates the turbine building and the auxiliary building (at Fire Area A-2). In SSA Amendment 1 the applicant requested a deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1 for this wall to the extent that it states that walls enclosing separate fire areas should have a minimum fire rating of 3 hours.

One division of safe shutdown equipment is located on the auxiliary building side of the steel wall in Fire Area A-2. The turbine building does not contain any safe-shutdown components. There are no significant fixed combustibles within 40 feet of the steel wall in Fire Area A-2. In addition, the presence of transient combustibles is unlikely since the main steam tunnel is not accessible during normal plant operation. The primary hazard in the turbine building would be a turbine oil fire from oil piping located under the turbine generator. A partial automatic fire suppression system installed in the entrance to the steam tunnel would protect the steel wall from this type of exposure fire from the turbine building.

On the basis of the partial suppression system, the negligible combustible loading in the vicinity of the steel wall, and the plant's ability to achieve and maintain safe shutdown even in the unlikely event that a turbine building fire breaches the steel wall and damages safe shutdown components in Fire Area A-2, the staff concludes that lack of complete 3-hour fire rated construction between the turbine building and the auxiliary building at the main steam tunnel is an acceptable deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1.

Fire Area A-1 is separated from Fire Area A-2 by 3-hour fire rated barriers except at the steel airlock walls that separate Fire Zone A-1b from Fire Zone A-2d. In SSA Amendment 1, the applicant requested a deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1 for these steel airlock walls. Fire Zone A-1b is a general access area in the auxiliary building. Division 1 safe-shutdown cables are located in the east side of the zone and Division 2 safe-shutdown cables are located on the opposite side of the zone. The intervening area between the Division 1 and Division 2 cables is protected by automatic sprinklers. Fire Zone A-2d is a general hallway and containment building personnel hatch area. The Division 1 cables in Fire Zone A-1b pass through Fire Zone A-2d and then to the fuel building. The staff was concerned that if a fire occurred in the vicinity of the steel walls, the ability to achieve safe shutdown would be adversely affected. However, as discussed in Section 9.5.5 of this report, in the event of such a fire, the staff has reasonable assurance that only one division of safe-shutdown cables would be damaged. Therefore, the ability to achieve

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safe shutdown would not be affected. On the basis of its review, the staff concludes that upgrading the steel airlock walls separating Fire Area A-1 from Fire Area A-2 to achieve a 3-hour fire resistance rating would not significantly increase the level of fire safety. The non-fire-rated walls are, therefore, an acceptable deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1.

In SSA Amendment 1 the applicant also requested deviations from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1 for unsealed air gaps in the floor slabs that separate Fire Areas A-1 and A-3, and for non-fire-rated containment and drywell electrical and piping penetrations. The 3-hour fire rated floor slabs separating auxiliary building Fire Areas A-1 and A-3 have an unsealed 2-inch-wide air gap where they meet the containment wall at elevations 737 feet 0 inch and 762 feet 0 inch. There are no significant combustibles located in the vicinity of the air gaps. Partial automatic fire detection systems are provided in both fire areas, and partial automatic sprinkler protection has been provided in Fire Area A-1. Shutdown divisions are separated and protected as delineated in the applicant's SSA. The staff was concerned that a fire originating in one of the fire areas would spread through the unsealed air gap into the adjacent fire area, damage redundant safe-shutdown systems, and adversely affect the plant's ability to shut down safely. However, the staff reviewed and evaluated conditions on each side of each air gap and found no significant unmitigated fire hazards that pose a credible threat to redundant safe-shutdown systems. Because of the fire detectors provided, the staff expects any fire to be detected in its incipient stage before significant fire propagation occurred. Moreover, because of the large volumes of the areas, the staff expects that the fire brigade would arrive before the room temperature rose significantly. The fire brigade would then take action to extinguish the fire in the area of orgin and protect redundant systems in the connecting area, if necessary. In the unlikely event that a fire spreads from one area to the other, resulting in damage to Methods 1 and 2 safe shutdown systems, the plant can still be shut down using Method 3 safe-shutdown systems as described in Section 9.5.5 of this SSER. On the basis of its evaluation, the staff concludes that the installation of fire rated seals in the air gaps penetrating the floor slabs separating Fire Areas A-1 and A-3 would not significantly increase the level of fire safety. The lack of 3-hour fire rated seals in these gaps is, therefore, an acceptable deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1.

Containment and drywell electrical penetration seals have not been tested or labeled as fire rated seals and piping, and are not externally sealed to provide a fire resistance rating. Each of the penetrations has been designed to withstand the pressures and temperatures associated with design-basis accidents. On the basis of its evaluations, the applicant concludes, and the staff concurs, that although the penetrations have not been subjected to the ASTM E-119 fire test standard, their construction and configuration are not conducive to fire propagation and, therefore, the probability is low that postulated fires will propagate from one fire area to another through the penetrations. The staff concludes that replacing the present containment and drywell penetration seals with fire rated seals would not significantly increase the level of fire safety. The staff finds that the lack of a 3-hour fire rating for seals in the containment and drywell penetrations is an acceptable deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1.

By letter dated December 6, 1985, the applicant informed the staff that it had identified twelve 4-inch-diameter and two 6-inch-diameter conduit penetrations

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through the drywell wall where a fire-tested sealant material cannot be installed because of the sealant's high viscosity, the amount of cable fill, and the required depth of the seals (at least 5 feet). The applicant compared the formulations of the fire-tested sealant and the proposed sealant (which displays the required flow properties). The comparison showed that the amount of elastomer, one of the base materials for fire resistance, per cubic foot of the proposed sealant is comparable to the amount of elastomer in fire-tested sealants. On this basis, the limited potential fire hazards in the areas, and the minimum depth of the seals (which are at least five times greater than the fire-tested seals for a 3-hour fire resistance rating), the staff concludes that the drywell conduit penetrations identified in the applicant's December 6, 1985, letter are acceptable. This is, therefore, an acceptable deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5.1.

In SSA Amendment 1, the applicant stated that enclosed stairwells in the control building are constructed of hollow concrete blocks with openings protected by labeled fire rated door assemblies. Steel columns are framed into the stairwell walls on the stairway side only. The stairwells are completely enclosed and are devoid of combustibles. Consequently, one would not expect a fire of sufficient magnitude or duration to damage the unprotected steel to occur within a stairwell. Moreover, because redundant safe-shutdown components are not located within the stairwells, the plant can be safely shut down following a fire in a stairwell. The stairwell design is, therefore, acceptable.

During the plant site audit of the applicant's fire protection program for Clinton the staff noticed that structural steel forming a part of a fire barrier in the diesel generator day tank room was not protected. By letter dated March 7, 1986, the applicant advised the staff that the subject steel is not structural steel and, therefore, does not require fire protection. On the basis of this clarification, the staff finds this issue resolved.

Also, during the plant site audit, the staff observed that bus duct penetrations through fire barriers were not sealed to provide a fire resistance rating at least equal to that of the barrier in accordance with Section D.1.(j) of Appendix A to BTP APCSB 9.5.1. In SSA Amendment 1, the applicant requested a deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1, and provided justification that adequate protection is provided for safe-shutdown components without the installation of fire rated seals in the bus ducts. The applicant's justification was based primarily on the equivalent design features of fire dampers and bus ducts and the fact that redundant safe-shutdown components or methods of shutdown are not located within 20 feet of any bus duct penetration. On the basis of the applicant's justification, the fuel loads in the areas through which bus ducts are routed, and the protection provided, the staff concludes that the installations of fire rated seals in the bus duct penetrations identified in Table 4.2.2.15-2 of Amendment 1 of the applicant's SSA would not significantly increase the level of fire safety. This is, therefore, an acceptable deviation from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1.

Section C.5.a.(3)(b) of BTP CMEB 9.5-1 states that the maximum temperature on the unexposed side of a penetration seal design should not exceed 325°F during the qualification fire test. By letters dated February 17 and March 19, 1986, the applicant identified three conduit penetration seal designs installed at Clinton for which the unexposed side temperatures exceeded 325°F during the qualification fire test, and provided the fire test reports for these penetration seal

designs. The three penetration seal designs were tested in accordance with the ASTM E-119 test standard. The fire exposure followed the ASTM E-119 standard time-temperature relationship for 3 hours. Each test specimen was subjected to a hose stream test following the 3-hour fire exposure. Temperatures in excess of 325°F were reached on the unexposed side of each of the three penetration seals at about 2 hours. However, all of the test specimens remained in place without passage of flame or ignition of cables on the unexposed side throughout the 3-hour fire exposure period, and remained intact and prevented the projection of water beyond the unexposed surface during the hose stream test. In addition, the temperatures of the unexposed faces of each penetration were less than both the self-ignition temperature of the cable insulation and the limiting end-point temperature specified in IEEE Std. 634, "IEEE Standard Cable Penetration Fire Stop Qualification Test", at the end of the 3-hour fire exposure. On the basis of its review of IEEE Std. 634 and the fire tests results of the three penetration seal designs identified in the applicant's March 19, 1986, letter, the staff concludes that the subject penetration seals meet Section M of Appendix R to 10 CFR 50 and are, therefore, acceptable.

9.5.2.2 Fire Doors and Dampers

By letter dated December 10, 1985, the applicant informed the staff that some fire door assemblies are installed with strips of polystyrene or polyethylene foam inside the hollow metal door frames. This foam was not part of the tested fire door assemblies. As justification, the applicant submitted a letter report from Factory Mutual Research which concluded that the relatively small quantity of either foam affords no appreciable hazard to the installation; nor does it decrease the fire door assemblies' expected fire resistance capabilities. Because a nationally recognized testing laboratory accepted the installed foam and because the foam is completely enclosed and isolated from ignition sources, the staff concludes that the fire door assemblies, as described in the applicant's December 10, 1985, letter, are acceptable.

In SSA Amendment 1, the applicant requested deviations from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1 to the extent that it states that door openings in walls enclosing separate fire areas should be protected with door assemblies having the fire resistance rating equivalent to that of the wall for non-fire-rated security airlock doors installed around the control room complex and for the airlock doors (hatches) provided in the containment and the drywell boundaries.

Fire Area CB-6 is located at elevation 800 feet 0 inch of the control building and includes the main control room, its peripheral rooms, and an access corridor. Three security airlock doors separate the access corridor from Fire Area CB-7, which is a stairwell tower and corridor, and from Fire Area CB-1, which included another stairwell tower and several lower elevations of the control building. Automatic fire detection is provided on each side of each security airlock door. The fuel load in the immediate vicinity of each door is low, and the airlocks do not contain in situ combustibles.

The airlock doors provided in the containment and drywell boundaries include equipment and personnel hatches and are described in Section 4.2.2.14.1 of SSA Amendment 1. Automatic fire detection is provided on the noncontainment side of each hatch. The fuel load in the vicinity of each hatch is low and the space betwen the hatches is devoid of combustibles.

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In the staff's opinion, considering the low fuel loads and fire hazards present and the fire protection provided, the airlock doors provide an acceptable level of fire protection for the areas in which they are installed. On the basis of its review, the staff concludes that the three non-fire-rated security airlock doors installed in Fire Area CB-6 and the non-fire-rated airlock hatches installed in the containment and the drywell boundaries are acceptable deviations from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1.

In the Clinton SER, the staff stated that the applicant had provided fire dampers in all duct penetrations of fire barriers. During the plant site audit of the applicant's fire protection program for Clinton, the staff observed that some ventilation ducts penetrating fire barriers were not equipped with fire dampers. By letter dated March 7, 1986, the applicant stated that it had completed a review of all duct penetrations and that, on the basis of the review, design modifications have been implemented to install fire dampers in all duct penetrations located in safe-shutdown areas of the plant, except where deviations have been approved by the staff. This is acceptable.

During the plant site audit, the staff also observed that the tracks and blades of fire damper assemblies were loaded with dirt and debris and that S hooks were installed backwards. In the March 7, 1986, letter, the applicant stated that a standard method for testing and documenting the functional ability of fire dampers was developed to ensure that all fire dampers are tested and inspected in accordance with manufacturer's instructions, are free from corrosion and dirt, and that the S hooks are installed properly. On the basis of the applicant's commitment, the staff finds that the concerns raised during the site audit are resolved.

In SSA Amendment 1, the applicant requested deviations from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1 in the auxiliary, fuel, and control buildings, and in the circulating water screenhouse to the extent that it states that penetrations through fire barriers for ventilation should be protected by fire dampers.

In the auxiliary, fuel, and control buildings, various fire barriers are penetrated by the standby gas treatment (VG) system ventilation piping. Fire dampers are not installed in the VG system piping that penetrates fire barriers. The VG system consists of two main piping loops routed through various fire zones and has exhaust ventilation openings in the fire zones. The main piping loops are constructed of seismically supported 14-inch welded steel pipe. The exhaust into the main loops is via 6- and 10-inch stubs. Each of the fire areas through which the piping is routed has fire detection capabilities as discussed in Section 9.5.1.4 of the Clinton SER and its supplements. The maximum fuel load in the zones through which the piping is routed yields an estimated fire severity of less than 30 minutes. The staff has reviewed the applicant's justification for this deviation from staff guidelines. On the basis of this review, the staff concludes that in view of the limited hazards and the low fuel loads present, the large volumes of the affected zones, the fire detection capability provided, and the construction and configuration of the VG system piping, the installation of fire dampers would not significantly increase the level of fire safety.

In the circulating water screenhouse, an undampered duct penetrates the floor/ ceiling assembly that separates Fire Areas M-1 and M-2. The duct is continuous

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through Fire Area M-1. The fuel load in each of these areas yields an estimated equivalent fire security of less than 20 minutes. On the basis of available fire protection, the limited fire hazards present on each side of the duct penetration, and the construction of the duct, the staff concludes that the duct will remain in place and prevent fire spread from one fire area to the other until the fire is extinguished by the fire brigade, or burns itself out. As a result of its evaluation, the staff concludes that the lack of fire dampers in the VG system piping and the duct penetrating the floor/ceiling assembly separating Fire Areas M-1 and M-2 are acceptable deviations from Section D.1.(j) of Appendix A to BTP APCSB 9.5-1.

By letter dated February 13, 1986, the applicant informed the staff that certain fire damper assemblies at Clinton have been installed with welds that are not specified in the manufacturer's installation instructions. The manufacturer's installation instructions require fire damper closure angles (perimeter mounting angles) to be welded to the damper sleeves. The closure angles are not shown to require attachment at the corners (angle-to-angle welding). However, certain fire damper closure angles at Clinton are welded together at the corners. By letter dated April 14, 1986, the applicant submitted a finite element heat transfer and stress analysis intended to show that the welded corner closure angles would not have any detrimental effects on the dampers to close and remain in place during a fire exposure. The staff reviewed the assumptions, the methods of analysis, and the analysis models and found them to be reasonably conservative, even though the consideration of the nonlinear behavior of the main structural elements is overly simplified. On the basis of its review of the information provided by the applicant, the staff concurs that the fire barrier provided by the subject fire dampers will not be compromised by deformation of the frame to which the damper assembly is attached during a severe fire exposure. The staff concludes, therefore, that the subject fire damper assembly installation are acceptable.

9.5.2.3 Conduits

Staff fire protection guidelines of Appendix A to BTP APCSB 9.5-1 do not specify the types of conduits that should be used in a plant. However, Section C.5.e.(1) of BTP CMEB 9.5-1 states that only metallic tubing should be used for conduit and that thin-wall metallic tubing should not be used. By letter dated November 1, 1985, the applicant informed the staff that 15 Schedule 40 aluminum conduits, 2 transite sleeves, and numerous electrical metallic tubing (EMT), also known as thin-wall, conduits are installed at Clinton.

The Schedule 40 aluminum conduits meet Section C.5.e.(1) of BTP CMEB 9.5-1 and are, therefore, acceptable.

Transite is a mixture of asbestos and a cementlike binder which does not support combustion or develop smoke when subjected to Underwriters Laboratories (UL) Test Standard 723, "Test for Surface Burning Characteristics of Building Materials." In view of these properties and its limited use, the staff finds that the transite sleeves installed in the plant do not degrade the level of fire safety and are, therefore, acceptable.

EMT is used in the plant for routing of communications, lighting, and fire detection system circuits. Based on EMT listed in the UL "Building Materials

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Directory" under approved fire stop systems and the applicant's commitment to seal inside these conduits in accordance with the sealing criteria approved in SSER 5, the staff finds the use of EMT as described in the applicant's November 1, 1985, letter to be acceptable.

9.5.4 Fire Protection for Specific Areas

9.5.4.1 Control Room

During the plant site audit of the applicant's fire protection program for Clinton, the staff observed that the control room was not adequately separated from its peripheral rooms and that automatic sprinkler protection was not provided in the peripheral rooms in accordance with staff guidelines of Section F.2 of Appendix A to BTP APCSB 9.5-1. In SSA Amendment 1, the applicant requested a deviation from this guideline. As shown on SSA Figure FP-14b, the peripheral rooms are now separated from the control room by 2-hour fire rated construction and are provided with complete fire detection coverage. Because there is little fire hazard associated with the peripheral rooms, they are equipped with fire detectors, and because the control room is constantly attended, there is reasonable assurance that a fire in any peripheral room would be promptly detected and extinguished by the operators with available equipment before threatening the control room. On these bases, the staff concludes that the existing construction and protection of the control room peripheral rooms is acceptable.

9.5.4.3 Containment and Reactor Building

In the SER, the staff reported that an oil collection system is not required for the reactor coolant pumps. This is an acceptable deviation from Section III.O of Appendix R to 10 CFR 50.

9.5.4.6 Other Plant Areas

Section D.2(b) of Appendix A to BTP APCSB 9.5-1 states that bulk compressed gases should not be stored inside safety-related buildings. In SSER 5, the staff requested that the applicant meet this guideline in the control building. In Section 4.0 of FPER Amendment 1, the applicant stated that bulk gas storage is located remote from safety-related structures. This meets Section D.2(b) of Appendix A to BTP APCSB 9.5-1 and is, therefore, acceptable.

9.5.5 Fire Protection of Safe-Shutdown Capability

By letter dated December 16, 1982, the applicant submitted its safe-shutdown analysis. In this analysis, and during a meeting with the staff on February 16-17, 1983, the applicant committed to install a fire rated wrap on the Division 2 switchgear room ventilation supply and return ductwork to ensure post-fire safe-shutdown capabilities. By letter dated April 4, 1983, the applicant committed to provide the results of a fire test conducted on the proposed fire wrap. By letter dated March 18, 1985, the applicant provided the test results. By letter dated October 25, 1985, the applicant stated that on the basis of its updated SSA, the fire wrap is not required on the subject ductwork to ensure safe shutdown of the plant, and that the wrap was not, therefore, installed. This is acceptable.

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By letter dated September 6, 1985, the applicant submitted an updated SSA report. Through this report, the applicant requested approval of deviations from Section III.G of Appendix R to 10 CFR 50. In SSER 5, the staff approved the applicant's request for deviation in Fire Area D-8, denied the applicant's request for deviation in Fire Area C-1, stated that the applicant has not provided sufficient information for the staff to complete its review of the remaining deviation requests, and stated that the deviations approved in SSER 3 were no longer valid. In SSA Amendment 1, the applicant provided additional information on the deviation requests and a reanalysis of the postfire safe-shutdown capability in accordance with Appendix R of 10 CFR 50. The staff's evaluation of these deviations and the safe and alternative shutdown capabilities are contained in the paragraphs that follow.

Deviations

Fire Area A-1 is located at elevations 707 feet 6 inches and 737 feet 0 inch of the auxillary building; Fire Area CB-1 consists of nine fire zones extending from elevation 702 feet 0 inch to elevation 825 feet 0 inch of the control building; Fire Area F-1 is the entire fuel building; Fire Area CB-5 is located at elevation 781 feet 0 inch of the control building; and Fire Area D-10 is located at diesel generator building elevation 762 feet 0 inch. The criteria of Section III.G.2 of Appendix R to 10 CFR 50 are not met in these areas because redundant safe-shutdown components (1) are not separated by 3-hour fire rated barriers, (2) are not separated by more than 20 feet free of intervening combustibles with fixed areawide automatic suppression, or (3) are not enclosed in 1-hour fire rated barriers with fixed areawide automatic suppression.

Divisions 1 and 2 safe-shutdown cables and equipment are located in Fire Area A-1. Division 2 safe-shutdown cables are routed in trays along the entire length of the north side of the area. Division 1 safe-shutdown cables enter from the east side of the area and are routed in trays and conduit for one-half of the length of the area above the Division 2 cables. These Division 1 and 2 trays are separated by a concrete cantilever. Moreover, the Division 2 cables are protected by a 1-hour fire rated barrier where both divisions are routed within 20 feet of each other.

Additional Division 1 and Division 2 cable trays and risers are located in Fire Area A-1. The Division 1 cables are confined to the east end of the fire area and the Division 2 cables are confined to the west end of the area. The redundant cable trays are separated by 136 feet and the redundant cables in conduits are separated by at least 72 feet. With the exception of the zones identified in Section 9.5.1.4 of SSER 5 and this sixth supplement, automatic fire detectors are provided. Automatic sprinklers are installed between the redundant divisions as delineated in Section 3.1 of SSA Amendment 1. Areawide sprinkler protection is not provided.

Fire Zones CB-1a and CB-1b contain one shutdown-related cable in conduit associated with the Division 2 fuel oil storage tank level indication. This cable's redundant counterpart is located in a separate fire area. Fire Area CB-1c contains safe-shutdown equipment and cables belonging to Methods 1 and 2. There are no Method 3 safe-shutdown components located in this zone. This zone is equipped with a fire detection system. Fire Zones CB-1d and CB-1e contain both Division 1 and Division 2 safe-shutdown components. All Division 2 systems

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that pass within 20 feet of Division 1 systems are protected by 1-hour fire rated barriers. Partial fire detection system coverage is provided and partial automatic sprinkler system coverage is provided over the cable systems as shown on SSA Drawings FP-10b and FP-11b. Fire Zones CB-1f and CB-1g also contain both divisions of safe-shutdown cables. One division of cable trays in each zone is protected by 3-hour fire rated barriers. Each zone is equipped with a fire detection system. Fire Zone CB-1i is as discussed in Section 9.5.1.4 of this supplement. If a fire damages redundant control room ventilation system cables located in this zone, safe shutdown can be achieved from the remote shutdown panel.

The maximum equivalent fire severity for any of the aforementioned control building fire zones is less than 30 minutes. In addition, all cable risers are sealed at the floor and ceiling with 3-hour fire rated seals, and the open hatches between elevations are protected by an automatic sprinkler system in accordance with Appendix A to BTP APCSB 9.5-1.

Fuel building Fire Zones F-1a and F-1b contain redundant safe-shutdown cables separated by a horizontal distance in excess of 75 feet. Balance of plant (BOP) cable trays are routed between the redundant cables such that the BOP trays are horizontally separated from the Division 1 and 2 cables by distances in excess of 15 feet and 6 feet, respectively. In addition, Fire Zone F-1b contains one cable and one instrument required for safe shutdown. Their redundant counterparts are located more than 100 feet away in Fire Zone F-1a. The intervening space is substantially free of intervening combustibles. Fire Zone F-1m contains redundant safe-shutdown cables separated from one another by 140 feet free of intervening combustibles. In addition, several Division 1 power and control cables in conduits are routed through Fire Zone F-1n within 20 feet of Division 2 power and control cables in conduits. Fire Zone F-1p contains redundant safe-shutdown-related cables separated by at least 46 feet free of significant intervening combustibles. The maximum equivalent fire severity for any of the fuel building fire zones is less than 30 minutes. In addition, all cable risers are sealed at the floor and ceiling they penetrate with 3-hour fire rated seals. With the exception of Fire Zone F-1n, each of these fire zones is equipped with fire detectors. Fire Area CB-5 contains Division 1 safe-shutdown cables in conduits and Division 1 and Division 2 safe-shutdown cable risers. The cables in conduit are protected by a 3-hour fire rated barrier. The cable risers are separated from the remainder of the area by 2-hour fire rated barriers. An areawide fire detection system is provided. Automatic sprinkler protection is provided for the cable risers. Areawide automatic sprinkler protection has not been provided. Fire Area D-10 contains Division 1 and Division 2 safe-shutdown cables in conduits. These cables are separated by about 40 feet. The fuel load in this area yields an equivalent fire severity of less than 30 minutes. A partial automatic sprinkler system is installed between the redundant shutdown cables and over the BOP cables located in the area. Areawide sprinkler protection has not been provided.

The staff was concerned that a fire in Fire Areas A-1, CB-1, F-1, CB-5, or D-10 would damage redundant safe-shutdown-related systems and adversely affect safe plant shutdown. However, because of the low in situ fuel load present, the staff does not expect a fire of significant magnitude or duration to occur in any of the subject fire areas. Should a fire occur in any of these areas, the staff has reasonable assurance that it would be detected by the fire detectors

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and extinguished by the plant fire brigade before damaging redundant safe-shutdown components. If the fire spreads rapidly, the perimeter construction of the individual zones, the fire rated penetration seals, the fire rated cable protection, the partial sprinkler system coverage, and the physical separation of redundant systems would all contribute to protect redundant systems until the fire brigade extinguishes the fire or it burns itself out.

The staff had additional concerns about Fire Zones F-1a and F-1n. In Fire Zone F-1a, the staff was concerned that a fire could spread to redundant divisions via the intervening BOP cable trays. However, for a fire in Zone F-1a to damage redundant divisions, an exposure fire in the vicinity of the Division 1 cables, for example, would have to damage the Division 1 cables, ignite the BOP cables located about 15 feet away, propagate at least 75 feet along the BOP cables, and then damage the Division 2 cables located about 6 feet from the BOP cables. In the staff's opinion, this scenario is unlikely because of the ignition and flame spread resistances of the IEEE Std. 383-qualified cables installed at Clinton. The staff concluded, therefore, that there is reasonable assurance that the intervening BOP cables in Fire Zone F-1a will not contribute to the loss of safe-shutdown capability as a result of a fire originating in the zone. In Fire Zone F-1n, the staff was concerned that a fire occurring in the vicinity of the Division 1 and 2 power and control cables located within 20 feet of one another might cause the valves required for safe shutdown to spuriously operate and adversely affect safe shutdown. However, by letter dated May 29, 1986, the applicant informed the staff that it had reviewed the subject valves and determined that, regardless of their position, the shutdown service water system will perform its intended function. These valves and their associated equipment will be deleted from the SSA. This new information resolves the staff's concerns about a fire in the vicinity of these cables.

On the basis of its evaluation, the staff concludes that the existing level of fire protection for Fire Areas A-1, CB-1, F-1, CB-5, and D-10 as delineated in SSA Amendment 1, is adequate. The deviations from Section III.G.2 of Appendix R to 10 CFR 50 requested by the applicant for these areas are, therefore, acceptable. This evaluation supersedes the staff's evaluations of deviations from providing automatic fire suppression systems approved in SSER 3.

The applicant has requested a deviation from providing an areawide automatic fire suppression system in accordance with Section III.G.2 of Appendix R to 10 CFR 50 for Fire Area C-1. Fire Area C-1, the drywell volume of the containment building, contains Division 1 and 2 safe-shutdown components. All cables, except those attached beneath the reactor, are enclosed within conduits. Shutdown-related components are separated by more than 20 feet, except at elevation 764 feet 0 inch where Division 1 and 2 cables for the dual-power safety relief valves (SRVs) cross and run within 1 foot of each other. The fuel load in the area is negligible. Fire detectors are provided for the reactor recirculation pump motors. The guidelines of Sections III.F and III.G of Appendix R to 10 CFR 50 are not met in this area because an areawide fire detection system has not been provided, and because redundant trains are not separated by a horizontal distance of more than 20 feet.

The staff was concerned that because of the absence of an areawide fire detection system a fire could develop undetected and, because of the lack of 20 feet of separation between the redundant cables at elevation 764 feet 0 inch, the

fire would damage redundant shutdown-related systems before it was extinguished. However, the principal fire hazards are the reactor recirculation pump motors. Each pump is covered by fire detectors. Therefore, the staff has reasonable assurance that any pump fire will be discovered during the incipient stage. Moreover, because the lubricating oil is contained within cooling coils installed within reservoirs and is not pressurized, and because no other combustibles are in the area, the staff does not expect a pump fire to spread beyond the immediate area of the pump. Furthermore, the applicant stated that a sufficient number of SRVs would be available to achieve safe shutdown if all cabling and equipment located within any 20-foot horizontal portion of the drywell were damaged by a fire. It is the staff's opinion that, given these conditions, any anticipated drywell fire would not propagate sufficiently either horizontally or vertically to damage enough redundant components to affect safe plant shutdown before either burning itself out, or before being extinguished by the fire brigade. On these bases, the staff has concluded that the installation of an areawide fire detection system or the separation of redundant cables at elevation 764 feet 0 inch would not significantly increase the level of fire safety. Therefore, the lack of an areawide fire detection system and cable separation are acceptable deviations from Sections III.F and III.G of Appendix R to 10 CFR 50, respectively.

In SSA Amendment 1, the applicant requested a deviation from Section III.G.3 of Appendix R to 10 CFR 50 for the control room to the extent that it requires the installation of a fire suppression system in a room for which alternate shutdown capability is provided. Because the control room is continuously manned and is provided with an automatic fire detection system, there is reasonable assurance that if a fire should occur, it would be discovered in its early stages. Also, because manual fire-fighting equipment and a partial-coverage fire suppression system has been provided, there is reasonable assurance that any fire would be extinguished before causing significant damage. In the event a control room fire causes damage to redundant safe-shutdown systems or evacuation of the control room, the alternate shutdown system would be used to achieve and maintain safe plant shutdown, On the basis of this evaluation, the staff concludes that the installation of an automatic fire suppression system in the control room would not significantly increase the level of fire safety. Therefore, not providing an automatic suppression system in the control room is an acceptable deviation from Section III.G.3 of Appendix R to 10 CFR 50.

In Section 9.5.5 of SSER 5, the staff stated that linear thermal detectors would be installed along the conduits located in Fire Area D-8. In fact, local thermal detectors will be provided. This change does not affect the staff's conclusions in SSER 5.

Safe-Shutdown Capability

The applicant's safe-shutdown capability reanalysis asserted that redundancy exists for systems needed for hot and cold shutdown, and identified the components, cabling, and support equipment needed to achieve hot and cold shutdown. Thus, in the event of a fire anywhere in the plant, at least one train of systems was identified as available to achieve and maintain hot shutdown and proceed to cold shutdown.

A combination of the following systems would be available during and after a fire anywhere within the plant to maintain the reactor in the hot-shutdown condition:

residual heat removal system, pressure relief system (automatic depressurization system and safety/relief valves), reactor core isolation cooling system, low-pressure core injection system, and the high-pressure core spray system. For cold shutdown, at least one train of the residual heat removal (RHR) system would be available. The RHR system would be used for long-term decay heat removal and would provide the capability to achieve cold shutdown within 72 hours after a fire. The availability of these systems includes the components, cabling, and support equipment necessary to achieve cold shutdown. The support equipment includes the diesel generators, shutdown service water system, Class 1E switch gear, motor control centers, distribution panels, batteries, and the necessary ventilation systems and instrumentation.

Although the applicant's analysis demonstrates that the reactor core could become uncovered for a short period of time from the effects of a fire, the staff has evaluated this scenario and concludes that the time the core would be uncovered is too short to result in damage to the fuel.

The applicant performed a study of electrical separation in order to ensure that at least one train of the necessary equipment would be available in the event of a fire in areas which might affect these components. Safe-shutdown equipment and cabling was identified and traced through each fire area from the components to the power source. A computer-based routing analysis and an intensive drawing review were performed for the Clinton Power Station electrical systems to identify equipment and cabling that is associated because of shared common power sources or common enclosures that could be adversely impacted by a fire. Associated circuits whose fire-induced spurious operation could affect shutdown were identified by a system review to determine those components whose spurious operation could affect shutdown. These spurious operations are to be prevented or terminated by operator actions which are to be contained in the plant emergency operating procedures.

The following are the only high-/low-pressure interfaces where electrically operated valves are relied on for isolation: reactor head vent valves, residual heat removal suction valves, and the residual heat removal valves in the inlet line to the RHR heat exchangers. The means for prevention of spurious operation of these high-/low-pressure interface valves that is required after the control room is abandoned has been addressed as follows by the applicant:

(1) Power of one of the reactor head vent isolation valves (1BZ1-F001 and 1BZ1-F002) has been removed by locking open the circuit breaker. Since these valves are in series and power is removed from one of the valves, spurious operation as a result of fire damage to the control cables will not result in a breach of this high/low interface. Furthermore, because these valves are powered by 3-phase 480-V ac, spurious operation due to fire-damaged power cables between the circuit breaker and the valve motor of the locked closed valve is not considered credible since shorting and alignment of the three power cables is unlikely to be achieved.

(2) Power for one of the two residual heat removal suction valves in series (1E12-F008) has been removed by locking open the circuit breaker. Since this is the same situation as with the reactor head vent valves, spurious operation of this valve as a result of fire damage to the cable is not considered credible.

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(3) Valves 1E1Z-F052A and 052B, 1E12-F087A and 087B, and 1E12-F051A and 051B comprise a high/low interface in the train A inlet line to the RHR heat exchangers. Valves 1E12-F051A and 1E12-F087A are in parallel with each other, and are in series with valve 1E12-F052A. The corresponding valves in the B train have the same arrangement. Power for both valves 1E12-F052A and 052B has been removed by locking open the circuit breakers. Since valves 1E12-F052A and 052B are in series with valves 1E12-F087A and 051A and valves 1E12-F087B and 051B, respectively, spurious operation as a result of fire damage to the control cables of these valves will not result in a breach of this high/low interface. The power to the corresponding valves in train B is also to be removed. Furthermore, because these valves are powered by 3-phase 480-V ac, spurious operation due to fire-damaged power cables between the circuit breaker and the valve motor of these locked closed valves is not considered credible since shorting and alignment of the three power cables is unlikely.

The staff has reviewed the applicant's method of determining that the separation criteria are met, that the associated circuits identified by the applicant are correct, and the actions necessary or modifications made to prevent spurious operation that would affect safe shutdown are reasonable. The applicant's design is in accordance with Branch Technical Position (BTP) CMEB 9.5-1, Section C.5.b, in all fire areas, except the following areas for which the applicant has requested deviations: F-1m, F-1n, C-2, CB-1e, CB-1f, CB-1g, CB-5a, and D-10. These deviations are evaluated in the preceding paragraphs of this section.

On the basis of its review, the staff concludes that the applicant has adequately addressed the effects of associated circuit interaction, and that the necessary isolation devices and the actions proposed in emergency procedures are adequate to ensure that such circuit interactions will not prevent safe shutdown. The staff further concludes that the applicant's methodology for verifying that separation is in accordance with BTP CMEB 9.5-1, Section C.5.b, is acceptable.

The applicant's reanalysis indicated that the only area outside containment where redundant divisions are not separated by barriers in accordance with BTP CMEB 9.5-1, Section C.5.b, is the control building area. Alternate shutdown measures are required for fires in the control building area in order to ensure the availability of the safe-shutdown systems. In the event that a fire disables the main control room, the remote shutdown panel located in a separate fire area of the auxiliary building provides an alternative to fire protection separation within the control building. The control functions and indications provided at the auxiliary control room panel are electrically isolated, or otherwise separate and independent from the main control room. Further discussion of alternate shutdown capability is presented below.

The staff concludes that the systems identified for achieving and maintaining safe shutdown in the event of a fire are acceptable. Further, the staff concludes that the methodology used to ensure adequate protection of safe-shutdown systems is in accordance with the guidelines of BTP CMEB 9.5-1, Section C.5.b, and, therefore, is acceptable.

Alternative Shutdown Capability

The design objective of the remote-shutdown panel for the purposes of this evaluation is to provide the ability to achieve and maintain cold shutdown in the

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event of a fire that forces abandonment of the main control room. This is to be achieved at Clinton by depressurizing, using three safety/relief valves (SRVs), and cooling the reactor using the reactor core isolation cooling (RCIC) system and the residual heat removal (RHR) system.

The SRVs, the RCIC system, and the RHR system can be controlled at the remote-shutdown panel for maintaining hot standby. Separate manual operator actions performed at local stations for control of support systems and cold-shutdown systems will be used in conjunction with procedures to maintain hot standby and to achieve and maintain cold shutdown within 72 hours.

The design of the remote-shutdown panel complies with the performance goals outlined in BTP CMEB 9.5-1, Section C.5.c, and the operability requirements of the alternate shutdown systems outlined in IE Information Notice 85-09. Reactivity control is to be accomplished by a manual scram before the operator is to leave the control room. Alternatively, the opening of the output breakers on the feeders from the nuclear safety protective system buses, and on the auxiliary 120-V ac bus to the reactor protection system trip logic channels, will be used as a backup means of scramming the reactor and closing the containment and reactor vessel isolation valves. The reactor coolant makeup function is performed by the RCIC pump. All the necessary operator actions, including reactor scram, can be accomplished from outside the main control room. Manual operation of the safety/relief valves will allow cooling the reactor and reductions in pressure at a controlled rate until the reactor pressure becomes so low that the RCIC turbine will discontinue operation. This condition will be reached at 50 to 100 psig reactor pressure. The RHR system will then be operated in the shutdown cooling mode using the RHR heat exchanger to bring the reactor to a cold-shutdown condition.

The following instruments on the shutdown panel will be used to monitor process variables:

- reactor water level
- reactor pressure
- RCIC storage tank level
- suppression pool level
- drywell temperature
- suppression pool temperature
- diagnostic instrumentation for support equipment

The above instrumentation will all be isolated from the main control room.

The staff has reviewed actions to be required by the plant emergency procedures for achieving and maintaining safe plant shutdown following a fire. For hot standby, the immediate actions are mainly precautionary measures to ensure no spurious operations occur because of a control room fire. For achieving and maintaining cold shutdown, local operations may be required and are to be contained in the emergency procedures. The staff has reviewed the proposed actions and manpower requirements, and concludes they are in accordance with BTP CMEB 9.5-1, Section C.5.c, since they can be accomplished exclusive of fire brigade members and are so straightforward and uncomplicated that cold shutdown can be achieved within 72 hours.

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9.5.7 Technical Specifications

In the SER, the staff stated that the applicant verbally committed to follow the Standard Technical Specification with respect to fire protection. In SSER 1, the staff reported that the applicant documented this commitment in FSAR Amendment 14. In FSAR Amendment 38, the applicant informed the staff of its intention to delete the fire protection surveillance and operability sections of the Clinton Technical Specifications. In Amendment 38, the applicant also committed to incorporate an equivalent level of limiting conditions and actions into the plant administrative procedures. This meets the guidance given in Generic Letter 86-10 and is, therefore, acceptable.

9.5.9 Conclusions

On the basis of its review, the staff concludes that the applicant's fire protection program for Clinton, with approved deviations, meets the staff fire protection guidelines of Appendix A to BTP APCSB 9.5-1 and Appendix R to 10 CFR 50 and satisfies GDC 3. The approved deviations are as follows:

(1) use of more than 75 feet of fire hose at certain hose stations (SSER 6, Section 9.5.1.2)

(2) lack of areawide fire detection in certain safety-related areas (SSER 5 and SSER 6, Sections 9.5.1.4 and 9.5.5)

(3) conduit sealing criteria (SSER 5, Section 9.5.2.1)

(4) certain fire areas bounded by 2-hour fire rated barriers (SSER 6, Section 9.5.2.1)

(5) lack of complete 3-hour fire rated barrier between Fire Areas T-1 and A-2, Fire Areas A-1 and A-2, and Fire Areas A-1 and A-3 (SSER 6, Section 9.5.2.1)

(6) non-fire-rated containment and drywell electrical penetrations (SSER 6, Section 9.5.2.1)

(7) lack of fire rated seals for bus duct penetrations (SSER 6, Section 9.5.2.1)

(8) non-fire-rated special-function doors in certain fire area boundaries (SSER 5 and SSER 6, Section 9.5.2.2)

(9) lack of fire dampers in standby gas treatment system ventilation piping penetrating fire area boundaries and in the circulating water screenhouse (SSER 6, Section 9.5.2.2)

(10) fire damper assemblies installed with welds in addition to those specified by the damper manufacturer (SSER 6, Section 9.5.2.2)

(11) lack of automatic sprinklers in the control room peripheral rooms (SSER 6, Section 9.5.4.1)

(12) lack of areawide automatic fire suppression system, fire barriers, or separation between redundant safe-shutdown components in accordance with Section III.G. of Appendix R to 10 CFR 50 in certain fire areas (SSER 5 and SSER 6, Section 9.5.5)

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(13) lack of oil collecton systems for the reactor coolant pumps (SER and SSER 6, Section 9.5.4.3).

The staff will condition the operating license with the following license condition (License Condition 22) that requires the applicant to implement and maintain in effect all provisions of the approved fire protection program.

> The licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the Clinton Power Station, Unit No. 1, and as approved in the Safety Evaluation Report (NUREG-0853) dated February 1986 and Supplements 1 through 6 thereto, subject to the following provision:
>
> The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

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11 RADIOACTIVE WASTE MANAGEMENT

11.4 Solid Waste Management System

11.4.1 System Description and Review Discussion

Section 11.4.1 of the FSAR indicated that wet solid wastes (spent resin, evaporation bottoms, filter sludges, etc.) will be combined with cement to form a solid matrix utilizing a permanently installed solid waste management system. In Amendment 34 to the Clinton FSAR, the applicant revised Section 11.4 to incorporate the use of a mobile, rather than a permanently installed, solidification system. Subsequent to this revision, the applicant stated in a letter dated September 5, 1985, that Clinton will employ a bitumen volume reduction and solidification system referencing Associated Technology Incorporated (ATI) Topical Report ATI-VR-001-P-A, Supplement 1 to "ATI Transportable Volume Reduction and Bitumen Solidification System (VTR-III)," dated July 1985.

In a letter dated April 10, 1986, from G. Lainas (NRC) to S. Simpson (ATI) (which contained the staff's Safety Evaluation Report), ATI-VR-001-P-A, Supplement 1, was accepted for referencing in license applications and amendments to the extent specified and under the limitations delineated in the staff's report. The basis for the staff's acceptance was the conclusion that the ATI system is designed and can be operated in accordance with the current guidance of applicable regulatory guides, standard review plans, branch technical positions, and federal regulations with one exception. The exception is the acceptability of the waste form that is being reviewed by the staff separately based upon Supplement 2 to ATI-VR-001-P-A, "Bitumen as a Radwaste Solidification Agent" (October 25, 1985).

The applicant stated, in its September 5, 1985 letter, that no exceptions or deviations have been taken from ATI-VR-001-P-A, Supplement 1. Section 11.4 of the Clinton FSAR (Amendment 34) and Section 3.4 of the ATI topical report provided adequate information regarding the interface requirements between the Clinton Power Station and the ATI system. The ATI mobile system will be located outdoors in the truck loading bay of the Clinton radwaste building. The equipment arrangement drawings are provided in the ATI topical report.

The ATI System (VTR-III) utilizes a high-temperature heating fluid and an electric resistance heat exchanger to evaporate waste water in the waste evaporator. The temperature characteristics of the heating fluid are:

- minimum open cup flash point: 575°F
- minimum spontaneous ignition point: 910°F

The waste evaporator operates at a waste product outlet temperature of 320°F. The temperature of the heating fluid is controlled and interlocked so as not to exceed 470°F. Should the temperature of the fluid exceed 465°F, an alarm is sounded. Should the temperature exceed 470°F, an interlock initiates an automatic shutdown of the process which includes turning off the heating elements. A redundant-temperature monitor and high-temperature interlock provide assurance of high-temperature protection.

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The bitumen storage tank, with a 1500-gallon capacity (5 feet in diameter and 5 feet high), will be located adjacent to the ATI system. At no point in the process system will the bitumen temperature exceed 340°F. The temperature characteristics of bitumen are:

- minimum open cup flash point: 600°F
- minimum spontaneous ignition point: 800°F

The temperature of the bitumen in the bitumen storage tank will be maintained between 280°F and 330°F by a self-contained electric heater with a temperature controller. The high-temperature switch alarms and shuts off the tank heater at 330°F.

The staff finds that the ATI system to be utilized at Clinton Power Station is designed and can be operated so that the temperature of any combustible is controlled to minimize the potential for combustion. Furthermore, the ATI system will be located outdoors, away from the buildings that house safety-related equipment.

Section 11.4.1 of the SER also stated that the applicant has committed to develop and implement a process control program (PCP) to ensure complete solidification of wet solid radwaste. The applicant has submitted an acceptable Clinton PCP in conjunction with the ATI generic PCP. The ATI topical report describes a PCP which ensures the production of a solid homogeneous, monolithic, water-free waste form. The PCP specifically and quantitatively addresses:

(1) the drawing and analysis of waste samples

(2) adjusting the chemistry and concentration of the waste with various additives or reagents

(3) setting feed rates and ratios of bitumen and waste into the evaporator

(4) temperature control of the evaporator.

11.4.2 Evaluation Findings

The staff finds that the Clinton PCP, in conjunction with the ATI PCP, meets NRC Branch Technical Position (BTP) ETSB 11-3, Revision 2, and, therefore, is acceptable.

After the SER was issued in February 1982, a new regulation, 10 CFR 20.311, became effective in December 1982. This regulation requires, among other things, any licensee who transfers radioactive waste to a land disposal facility to prepare all wastes so that the waste product meets the waste characteristic requirements set forth in 10 CFR 61.56.

The applicant stated in a letter dated January 28, 1986, that it has committed to operate the ATI system and prepare all wastes in accordance with ATI-VR-001-P-A, Supplement 2. The staff is currently reviewing this topical report. Upon completion of its review, the staff will issue a supplement to the Clinton SER concerning the capability of the Clinton Power Station to meet the requirements set forth in 10 CFR 61. In the interim, the staff has determined that the applicant cannot transport any solidified waste product to

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a licensed waste burial site without prior approval from the burial site operator. When the staff completes its review and if Supplement 2 to the ATI topical report is found to be acceptable, any additional requirements imposed by the burial site operator that results in a change in system design or PCP must also be reviewed by the staff.

11.5 Process and Effluent Radiological Monitoring and Sampling Systems

By a letter dated December 3, 1985, the applicant submitted a variance request to delay the empirical predetermination of iodine and particulate sample line loss correction factor. The request asks for deferral until ongoing industry and staff research programs develop an acceptable methodology for performing such tests. An empirical predetermination of an iodine and particulate sample line loss correction factor is stated in Regulatory Guide 1.97, Revision 3 (May 1983).

Currently, there is an ongoing effort to develop an acceptable test methodology for determining iodine and particulate sample line loss. This effort is being pursued at the Department of Energy's Pacific Northwest Laboratory and Idaho National Engineering Laboratory under two separate technical assistance contracts with NRC.

The applicant has described in the FSAR the design methods employed in the gaseous effluent sampling system to provide representative samples. These include stainless steel sample lines, which are heat traced and insulated to minimize condensation. The design meets the intent of the guidelines specified by ANSI Standard N13.1-1969, "Guide to Sampling Airborne Radioactive Materials in Nuclear Facilities." The staff considers the steps taken by the applicant to minimize iodine and particulate plateout in sample lines to be appropriate at this time.

Therefore, the staff finds that the applicant's proposal to delay an empirical line loss predetermination to be acceptable, provided that the applicant uses an interim correction factor of two for iodine and particulate line losses for the high-range effluent radiation monitors during and following a postulated accident.

In SSER 5, the staff determined that the applicant's proposal for extending the existing heat tracing on the particulate/iodine sample assembly [for both the standby gas treatment system (SGTS) and heating, ventilation, and air conditioning (HVAC) stack sample lines] was acceptable, provided that the entire sample line, including the inlet and outlet, in addition to the portion proposed by the applicant and up to the sample cooler (for the SGTS sample line), be included. By letter dated January 27, 1986, the applicant submitted a variance request for not extending additional heat tracing onto the 1/8-inch inlet and outlet tubing of the iodine sample assemblies (SA-16) on the AXM-1 grab sample pellets. The staff finds the applicant's justification for this variance to be acceptable on an interim basis until definitive guidance on moisture condensation in the sample lines and on the sample assemblies is generated by the NRC staff. This finding is based on the following considerations: The applicant will be required to (1) utilize silver zeolite iodine cartridges, or the equivalent, to minimize iodine loss due to the potential moisture, and (2) use

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a correction factor of two to account for the degradation of the iodine collection efficiency due to the potential moisture condensation in SA-16 sample assemblies. The correction factor was proposed by the applicant in its January 27, 1986, letter.

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12 RADIATION PROTECTION

12.3 Radiation Protection Design Features

12.3.4 Area Radiation and Airborne Radioactivity Monitoring Instrumentation

12.3.4.1 Area Radiation Monitoring Instrumentation

In the SER and in SSER 4, the staff found that the high-range containment monitoring system complied with the provisions at TMI-2 Action Plan Item II.F.1(3) and was acceptable. In subsequent letters, dated October 17 and December 26, 1985, the applicant requested a variance from the in situ calibration requirement and linear energy exposure (±20%) for gamma photons of 0.1 MeV to 3.0 MeV requirement of NUREG-0737 for its two drywell high-range radiation monitors.

TMI Action Plan Item II.F.1(3), Table II.F.1-3, requires, in part, that the radiation detectors be calibrated in situ, with a calibrated radiation source for at least one decade below 10 R/hr. Since the two drywell monitors at Clinton are located in thin-walled penetration sleeves, the applicant proposed to perform the calibration of these monitors locally, on the containment side of the penetration sleeve. No electrical cables would be disconnected during the calibration. The electronic calibration over the detectors' higher ranges, e.g., 10^2 to 10^7 R/hr, would still be performed in situ, as per NUREG-0737 requirements.

Similarly, since the two drywell monitors are located in penetration sleeves, the radiation monitors will underrespond. The applicant proposes to develop a graphical time-dependent correction factor to correct the monitor readings.

The staff finds that the applicant's proposed procedure for correcting the underresponse to noble gas photons and calibrating its drywell high-range radiation monitors will ensure the instruments are operating properly and are calibrated in accordance with the intent of NUREG-0737, Table II.F.1-3. Therefore, the staff finds the applicant's proposed procedure acceptable.

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13 CONDUCT OF OPERATIONS

13.1 Organizational Structure of Applicant

The staff has received the additional information provided by the applicant through FSAR amendments since SER Supplement 5 was issued. The results of this review are provided below.

13.1.1 Management and Technical Support Organizations

The corporate organization and lines of responsibility for management and technical support of Clinton Unit 1 are shown on Figure 13.1. The applicant has reorganized the Clinton Power Station's technical support organization by adding the following departments or groups.

(1) Nuclear Program Assessment Group

(2) Scheduling and Outage Management Department

(3) Licensing and Safety Department

(4) Nuclear Projects Group

The addition of these four organizational elements raises to ten the number of managers reporting to the Vice President. The issue of extended span of control and possible overload of the Vice President was discussed with the applicant's staff representatives. The applicant provided a "record of coordination," dated May 29, 1986, which supplied additional explanation of how this organization would function. This explanation is summarized below.

The Manager Nuclear Program Coordination assists the Vice President and has the authority of the Vice President in carrying out the following delegated responsibilities.

(1) configuration management

(2) emergency response

(3) Regulatory Guide 1.97, accident monitoring instrumentation

(4) safety parameter display system

(5) detailed control room design review

(6) ASME N-stamp

The key managers that the Vice President will confer with on day-to-day issues of plant operation are the following:

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(1) Manager - Clinton Power Station is responsible for overall facility operation including the direction of the operations, maintenance, refueling, chemistry, radiation protection, radwaste, and technical activities. The delegation of training and outage management to other independent departments allows the Plant Manager to concentrate his efforts on the day-to-day operation of the plant.

(2) Manager - Nuclear Station Engineering is a key manager who is involved in resolving problems that arise in the operations of Clinton.

(3) Manager - Quality Assurance is responsible for the applicant's quality assurance program and is responsible for conducting audits of vendors and contractors. The size of the department and level of activity will decrease as the plant undergoes the transition from construction to operation. This is a key department in monitoring plant activities for issues affecting safety.

(4) Manager - Licensing and Safety is responsible for providing representation and interface with regulatory agencies. He is able to present safety issues independent of the engineering or the operations departments which could be responsible for their corrective action.

(5) Manager - Startup directs the day-to-day startup testing activities. The startup activities are coordinated and closely monitored by the Project Control Center under the supervision of the Manager Nuclear Program Coordination. This department will be eliminated after the plant is operational.

When power operation has begun and/or startup activities are completed, the Startup Department will be abolished. Then the normal day-to-day activities of operating the plant will usually require the Vice President to only interact with the remaining four key managers.

In addition to these four key managers, the Vice President is expected to interact with the other departments and groups reporting to him but on a less frequent basis. These departments/groups are:

(1) Director - Nuclear Training position was established as a separate department head to place greater emphasis on training. The activities of the training department incorporate feedback from plant operating experience (such as lessons learned) into the requalification program, but is independent of the day-to-day activities of plant operation.

(2) Director - Nuclear Review and Audit Group. The Nuclear Review and Audit Group (NRAG) is required to meet quarterly during the first year of operation and semiannually thereafter. NRAG is not expected to compete for the Vice President's attention or distract him from the day-to-day issues during plant operation.

(3) Director - Nuclear Program Assessment Group is responsible for coordinating the Institute of Nuclear Power Operations (INPO) programs and assessing Clinton programs. Issues raised from review of these programs are typically programmatic and not of a time-sensitive nature requiring an immediate resolution; therefore, they will not require the Vice President's frequent attention.

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(4) Manager - Nuclear Planning and Support is responsible for human resources, support services, material management, maintenance services, budgeting, site accounting, and program planning. He would not be directly involved in resolving problems that affect the safe operation of the plant.

(5) Manager - Scheduling and Outage Management is responsible for the coordination and preparation of schedules, management of contractor maintenance support, coordination of outage planning, and supporting the plant during scheduled and unscheduled outages to ensure early and efficient completion of all work. The major activities of this department occur when the plant is shut down.

The applicant has described and explained the organization for the management and technical support of the Clinton Power Station. This information has been reviewed and the staff concludes that the applicant has presented an organization and staff acceptable to meet the requirements expressed in Section 13.1.1 of the Standard Review Plan (SRP), NUREG-0800.

13.1.2 Operating Organization

13.1.2.1 Organization

The organization of the Clinton plant is shown on Figure 13.2. The applicant has modified the organization from that previously reviewed. The changes are the establishment of an Assistant Plant Manager position and the elevation of the major department Supervisors to Directors. The responsibilities of the various departments remain essentially unchanged except for a change in the Chemistry Supervisor position described below. The staff has reviewed this plant operating organization and judged that it meets the criteria expressed in SRP Section 13.1.2.

SSER 5 for Clinton Power Station documented the review and approval of Mr. Hedges as the Supervisor of Chemistry. Mr. Hedges possessed the educational qualifications in accordance with ANSI/ANS 3.1-1981, Section 4.4.3, "Chemistry and Radiochemistry." However, he lacked specific nuclear training in an operating nuclear power plant. Therefore, the applicant committed to provide this individual with specific nuclear training by assigning him to a chemistry section of an operating nuclear power plant for a period of 3 months and requiring successful completion of the nuclear steam supply system (NSSS) vendor chemistry and radiochemistry training program. In addition, the applicant committed to retaining an experienced consultant to assist the Supervisor of Chemistry.

Subsequently, in order to strengthen the management within the Chemistry Department, the applicant, in a letter dated March 20, 1986, stated that Mr. Hedges had been reassigned to the position of Assistant Supervisor of Chemistry and that Mr. W. P. Mullins had been assigned to the position of Supervisor of Chemistry. Mr. Mullins possesses qualifications in accordance with ANSI/ANS 3.1-1978, Section 4.4.3, "Chemistry and Radiochemistry." Furthermore, the consultant who was hired to assist the former Supervisor of Chemistry as specified in the Clinton FSAR, continues to work as an assistant to the present Supervisor of Chemistry.

Regulatory Guide (RG) 1.8 addresses nuclear power plant personnel selection and training and it endorses the criteria in ANSI/ANS 18.1-1971 for the selection

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and training of nuclear power plant personnel, including professional-technical personnel. As stated above, the applicant's current Supervisor of Chemistry, the current Assistant Supervisor of Chemistry, and the consultant all have qualifications which are of a higher level and therefore, more stringent than those stated in ANSI/N 18.1-1971.

Because the qualifications of the Supervisor of Chemistry, the Assistant Supervisor of Chemistry, and the consultant exceed the qualifications requirements endorsed by RG 1.8, the staff finds this revision acceptable.

13.3 Emergency Planning

13.3.1 Background

The staff's evaluation of the state of emergency preparedness associated with Clinton involves review of the applicant's onsite emergency plans and preparedness, as well as review of the Federal Emergency Management Agency (FEMA) findings and determinations pertaining to the adequacy of offsite (State and local) emergency plans and preparedness.

In September 1981 (FSAR Amendment 7), the applicant filed with the NRC its original emergency plan to meet the revised emergency planning requirements of 10 CFR 50. Since that time, the applicant has continued to upgrade its emergency plan based upon the installation and checkout of equipment and systems; refinements identified as part of its coordination with offsite authorities during the development of offsite planning; and continued discussions with the NRC staff. The applicant has submitted five revisions to its emergency plans which were filed with the NRC as follows: Revision 1, FSAR Amendment 16, May 1982; Revision 2, FSAR Amendment 28, December 1983. Revision 3 and all subsequent revisions of the emergency plan are maintained as a separate document and were incorporated by reference in the FSAR Amendment 31, September 1984. Revision 4 was dated December 15, 1984, and Revision 5 was dated November 30, 1985. The staff reviewed each of those revisions in detail and, where additional clarification was needed, discussed those matters with the applicant. The staff has completed its review and evaluation of the adequacy of the latest revised emergency plan (Revision 5) and the results of that evaluation are provided here.

The acceptance criteria used as the basis for the staff's review of the applicant's emergency plan are specified in Section 13.3, "Emergency Planning," of the Standard Review Plan (SRP), NUREG-0800, dated July 1981, and include: the planning standards of 10 CFR 50.47(b); the requirements of Appendix E to 10 CFR 50; and the specific guidance criteria of NUREG-0654/FEMA-REP-1, Revision 1, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," dated November 1980. The guidance criteria of NUREG-0654 have been endorsed in Regulatory Guide (RG) 1.101, Revision 2, "Emergency Planning and Preparedness for Nuclear Power Reactors," dated October 1981, and thus have the same status as a regulatory guide.

The applicant's responses to the deficiencies previously identified by the staff in SSER 4 as requiring revision or additional information are discussed in Section 13.3.2 below. Issues arising from the GUARD v. NRC decision on offsite medical arrangements are discussed in Section 13.3.3 below. The results of the

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NRC evaluation of the full-participation exercise are addressed in Section 13.3.4 and interim findings and determinations by FEMA on the adequacy of the State and local county emergency plans and preparedness are addressed in Section 13.3.5. The staff's conclusions are provided in Section 13.3.6 of this supplement.

13.3.2 Evaluation of the Applicant's Emergency Plan

13.3.2.1 Emergency Classification System

Item requiring resolution:

- The staff will confirm the adequacy of the applicant's final emergency action level (EAL) and initiating conditions scheme as part of its onsite implementation appraisal of the applicant's emergency preparedness program.

During the period of November 12-21, 1985, the NRC conducted an appraisal of the state of emergency preparedness at Clinton. The areas examined during the appraisal which apply to EALs and initiating conditions are described in Section 5 of NRC Inspection Report 50-461/85039, dated December 30, 1985.

The appraisal report identified three incomplete items relating to EALs and initiating conditions. These specific items are tracked formally and require resolution before fuel load. Another item relating to EALs and requiring resolution before fuel load was identified in the inspection report covering the December 4, 1985, joint full-participation exercise (50-461/85040, December 24, 1985). A followup inspection reported in Inspection Report 50-461/86021, March 30, 1986, closed two of the items mentioned above and identified a new item that was related to an EAL. Hence, at the present, there are three EAL-related items which require resolution before fuel load. NRC Region III personnel will ensure that inspection items associated with EALs are resolved before fuel load.

13.3.2.2 Public Education and Information

Item requiring resolution:

- The staff will confirm the acceptability of the applicant's public information material by comparison with the criteria in Part II.G. of NUREG-0654.

On the basis of a review of the applicant's public information material by NRC and FEMA, the public education and information program has been found to meet the criteria of NUREG-0654. The distribution to the public was found adequate in a followup inspection (Inspection Report 50-461/86021). The finding was based on the mailing of the material to customers of electricity in the 10-mile plume emergency planning zone (EPZ) and distribution of the materials to area hotels, motels, and recreation areas. This item is resolved.

13.3.2.3 Accident Assessment

Item requiring resolution:

- Detailed review of the emergency preparedness meteorological program will be included in a supplement to the SER.

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This issue was originally identified in SER Section 2.3.3 and is now covered under this section. The onsite meteorological measurements program to support an emergency was reviewed during the emergency preparedness implementation appraisal. The program was reviewed subsequent to the publication of the SER and is contained in Section 4.2.1.4 of Inspection Report 50-461/85039, December 24, 1985. A followup inspection (Inspection Report 50-461/86021, March 26, 1986) closed those items related to meteorology and requiring resolution before fuel load. Two items related to meteorology remain to be resolved. One requires the accumulation of data over a period of several months. The other requires the incorporation of stability data into some emergency plan implementing procedures (EPIPs) before exceeding 5% of rated power. The NRC Region III staff will verify the resolution of these items on a schedule to support licensing.

13.3.2.8 Emergency Facilities and Equipment (NUREG-0737, Item III.A.1.2)

In Supplement 5 to the SER, the staff stated that the applicant's request to perform the appraisal of the Clinton emergency response facilities (ERFs) after fuel load was acceptable. In addition, the staff stated that a license condition (License Condition 18) would be required related to the completion of the ERFs that is acceptable to the staff.

In a letter dated January 31, 1986, the applicant stated that the ERFs are essentially complete and that after fuel load a date for the appraisal of the Clinton ERFs that is mutually acceptable to the staff and the applicant will be established. The staff finds this commitment acceptable and because the ERFs are essentially complete, License Condition 18 is no longer required.

13.3.3 Offsite Emergency Planning Medical Services

In a recent decision, GUARD v. NRC, 753 F.2d 1144 (D.C. Cir. 1985), the U.S. Court of Appeals vacated the Commission's interpretation of 10 CFR 50.47(b)(12) to the extent that a list of facilities was found to constitute adequate arrangements for medical services for members of the public off site exposed to dangerous levels of radiation. The Commission has now provided guidance to be followed in determining compliance with this regulation pending its determination of how it will proceed in response to the Court's remand. In particular, the Commission directed that Licensing Boards, and in uncontested cases, the staff, should consider the uncertainty attendant to the Commission's interpretation of this regulation, especially in regard to its interpretation of the term "contaminated injured individuals." In GUARD, the Court left open to the Commission the discretion to reconsider whether that term should include members of the offsite public exposed to dangerous levels of radiation and, thus, whether arrangements for this population of individuals are required at all.

For this reason, the Commission observed that it may reasonably be concluded that "no additional actions should be taken now on the strength of the present interpretation of that term." Accordingly, the Commission observed that it can be found "that any deficiency which may be found in complying with a finalized post-GUARD planning standard (b)(12) is insignificant for the purposes of 10 CFR §50.47(c)(1)." In this regard, the Commission, as a generic matter, noted the low probability of accidents which might result in exposure of members of the offsite public to dangerous levels of radiation as well as the slow development of adverse reactions to overexposure. See, Emergency Planning; Statement of Policy, 50 FR 20892, May 21, 1985.

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Consistent with the foregoing Statement of Policy, on November 14, 1985, the applicant submitted a list of medical service facilities for the involved offsite response jurisdictions and committed to comply fully with the Commission's response to the Court's remand. By memorandum dated December 6, 1985, FEMA provided confirmation that a list of medical facilities has been identified for use in case of an emergency at Clinton. FEMA also identified other related and supporting arrangements and services in the same memorandum.

Accordingly, on the basis of the factors identified by the Commission in its Statement of Policy, the staff has determined that the requirements of 10 CFR 50.47(c)(1) have been satisfied so as to warrant issuance of the operating license pending further action by the Commission with respect to the requirements of 10 CFR 50.47(b)(12).

13.3.4 Emergency Preparedness Exercise

The NRC Inspection Report [50-461/85039 (DRSS), December 24, 1985] covering the joint full-participation exercise identified no violations of NRC requirements and six exercise weaknesses. Two of the six weaknesses require resolution before fuel load; one of these two weaknesses was resolved in a subsequent inspection [50-461/86021 (DRSS)]. The remaining exercise weakness requires a review of an emergency action level (EAL) as discussed in Section 13.3.2.1 above. The results of the FEMA evaluation of the exercise are addressed below in Section 13.3.5.

13.3.5 FEMA Finding on Offsite Preparedness

The interim finding by FEMA on the offsite radiological preparedness plans for Clinton was dated March 12, 1986, and was forwarded to the NRC by memorandum dated April 4, 1986. The interim finding was based on FEMA's Region V review of the Illinois Plan for Radiological Accidents, State General Plan (Volume I) and the preliminary site-specific plan for Clinton (Volume VIII), an analysis of the State's schedule of corrective actions for the planning inadequacies identified in the Regional Assistance Committee review, and an evaluation of the initial joint full-participation exercise conducted on December 4, 1985. FEMA found reasonable assurance that the health and safety of the public can be protected in the event of an incident at Clinton.

To ensure that the formal approval of offsite plans by FEMA is completed in a timely manner, the staff requires the following license condition (license condition 21):

> In the event that the NRC finds that the lack of progress in completion of the procedures in the Federal Emergency Management Agency's final rule, 44 CFR Part 350, is an indication that a major substantive problem exists in achieving or maintaining an adequate state of emergency preparedness, the provisions of 10 CFR Section 50.54(s)(2) will apply.

13.3.6 Conclusion

On the basis of the staff's review according to the criteria in "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," NUREG-0654/FEMA-REP-1, Revision 1,

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November 1980, the staff concludes that the emergency plan for Clinton provides for an acceptable state of emergency preparedness and meets the requirements of 10 CFR 50 and Appendix E thereto.

The Federal Emergency Management Agency has provided interim findings on State and local emergency response plans. FEMA concludes that there is reasonable assurance that the health and safety of the public can be protected in the event of an incident at the Clinton Power Station.

On the basis of NRC staff review of applicant's plans and procedures, the NRC and FEMA evaluation of the joint exercise, and NRC staff review of the FEMA findings, the staff finds that the state of onsite and offsite emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency.

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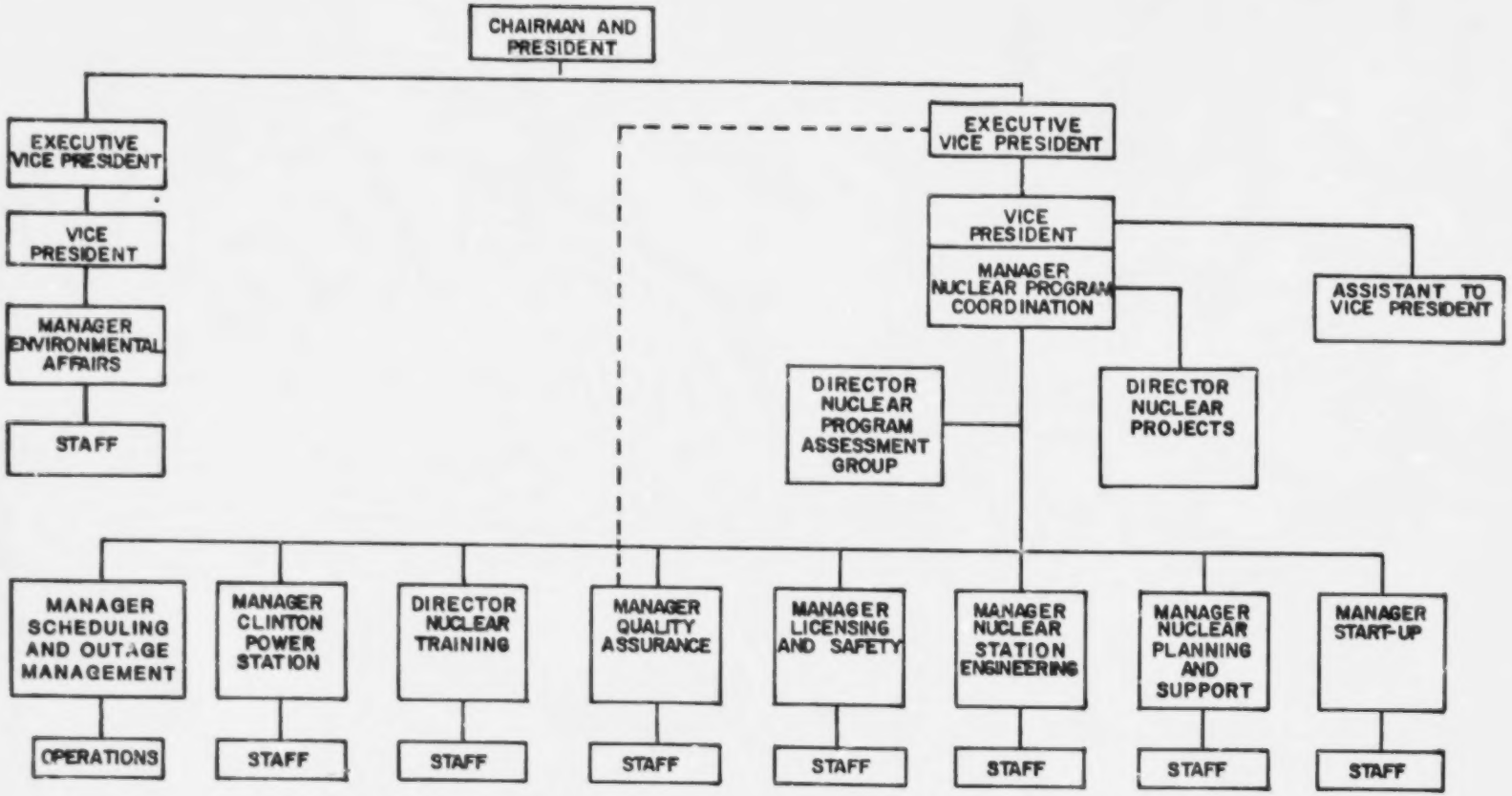

Figure 13.1 Management and technical support organization for Clinton Power Station

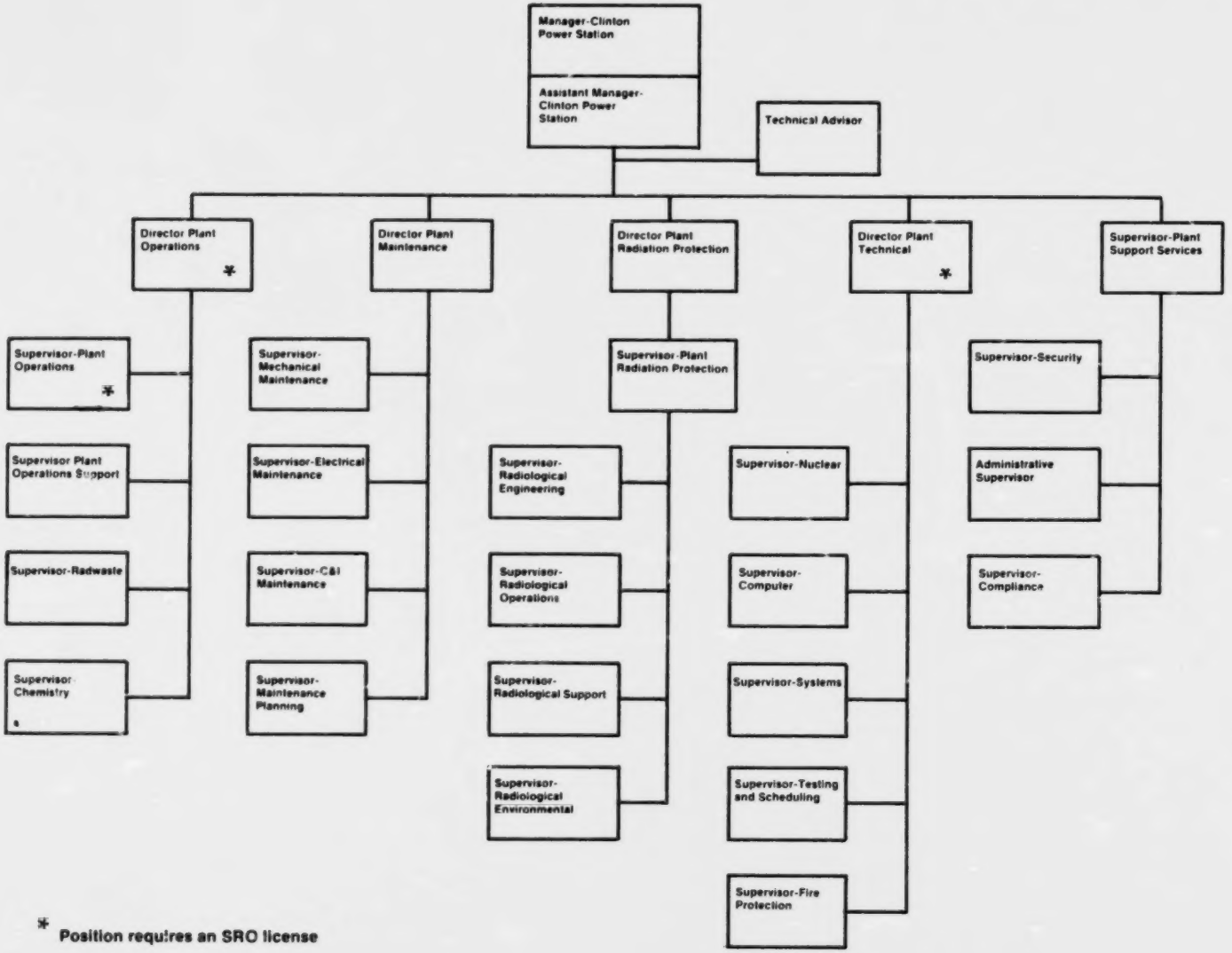

Figure 13.2 Plant operating organization for Clinton Power Station

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14 INITIAL TEST PROGRAM

Accelerated Power Ascension Test Program

The applicant, by letter dated February 5, 1986, requested changes to accelerate the Clinton Power Station power ascension test program (startup test phase). The changes to accelerate the Clinton power ascension test program are similar to the accelerated power ascension test program for Hope Creek Generating Station. The Hope Creek accelerated test program has been evaluated and that program is to serve as the lead plant for evaluating other boiling-water reactor (BWR) accelerated power ascension test programs.

In the letter referenced above, the applicant requested 21 changes to accelerate the power ascension test program. Because Hope Creek is the lead plant for accelerated power ascension test programs, the Hope Creek SER supplements have been referenced and used as the evaluation bases where applicable (letters to Public Service Electric and Gas (PSE&G) dated January 22, February 4, and March 20, 1986) for most of the startup tests for which the applicant has requested a test simplification.

BWR power ascension testing is carried out at defined regions of the core power-flow map and are identified as test conditions (TCs). These conditions are specified as heatup and TCs 1 through 6. TC 6 is full power and full flow. Since the following discussions frequently refer to these TCs, the TCs have been defined in Table 14.1 for reference.

Evaluation

The test program changes requested by the applicant have been referenced to the FSAR subsections to which they pertain and are discussed below.

(1) Chemical and Radiochemical, FSAR Subsection 14.2.12.2.1 (Startup Test 1.0)

The applicant proposes to delete the integrated performance testing of the reactor water cleanup (RWCU) system and condensate demineralizer (CD) system at TC 3.

In startup test No. 1.0, the RWCU and CD systems are performance tested to demonstrate that the plant water chemistry and radiochemistry comply within reactor water quality limits during the power ascension test program and also demonstrate the design capability of the plant chemistry systems. Startup test 1.0 requires the RWCU to be taken out of service to demonstrate the integrated performance of the RWCU and CD systems during TC 3 (lower power) and TC 6 (rated power/flow). This integrated performance test at TC 3 can verify procedures and provide preliminary data, but is not required to demonstrate meeting design specifications. Integrated performance testing of the RWCU and CD systems at TC 6 will demonstrate the ability of these systems to meet requirements at the most demanding plant operating conditions. Therefore, it is acceptable to delete the RWCU and CD systems integrated performance testing at TC 3 as proposed by the applicant.

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On the basis of the staff's evaluation, the deletion of the integrated performance testing of the RWCU and CD systems at TC 3 in startup test 1.0 meets the requirements of Regulatory Guide (RG) 1.68 (Rev. 2, August 1978), Appendix A, paragraphs 4.h and 5.a.a, and is, therefore, acceptable. This is consistent with the Hope Creek proposal which is identical in principle.

(2) Fuel Loading, FSAR Subsection 14.2.12.2.3 (Startup Test 3.0)

Startup test 3.0 is the fuel loading phase of initial operations. It has usually been necessary in past fuel loadings to use fuel loading chambers (FLCs) in addition to source range monitor (SRM) detectors to achieve Technical Specification required count rates with fuel in the core. A number of utilities have in the past requested and have been granted reload fuel loading operations in which a small number of fuel assemblies could be loaded before the usual required count rate on the SRM or the FLC was achieved. This initial loading is sufficient to provide the needed count rate. These exceptions are based on the fact that the permitted small number of assemblies cannot be critical, even with all control rods fully withdrawn. The proposed modifications to startup test 3.0 are to permit the loading of 16 assemblies without meeting the usual required 0.7 count/sec for the SRM or FLC. This test modification is based on analysis by the General Electric Co. (GE) which shows that this array would not be critical with rods out and would provide the necessary count rate. This change would make it unnecessary to use FLCs, which interfere with operations, and would permit the use of the standard SRM alone. However, the FLC could be used, if needed. The procedure places the sources in the alternate locations, close to the SRM, and uses a spiral loading pattern around the initial source SRM and 16 assembly locations rather than around the core center.

These procedures are compatible with a number of previously approved reload procedures. The criticality calculations are done with standard methodology. They are consistent with other analyses reviewed in this area. Tests on other reactor startups indicate that required count rates should be achieved. The Technical Specifications will require (after loading 16 assemblies) the usual count rate on at least one SRM (the SRM near the initial loading). The other SRMs will be checked with a source, as has been approved for other reactors, until they reach a suitable count rate. A new Technical Specification, 3/4.10.6, has been added to provide for this first-cycle revised procedure and surveillance.

On the basis of compatibility with previously approved reload procedures and the use of standard methodology, the staff finds the proposed Technical Specification 3/4.10.6 acceptable. This test simplification is identical to that proposed and approved for Hope Creek.

(3) Control Rod Drive System/Hot Friction Testing, FSAR Subsection 14.2.12.2.5 (Startup Test 5.1)

Part of the testing of the control rod drive (CRD) system includes friction testing at hot zero power and cold conditions. The results of the tests establish the performance of the CRDs relative to established limits on differential settling pressure. The applicant has proposed to limit to four the number of CRDs to be hot friction tested. The CRDs chosen will be the same four chosen for scram time testing during plant heatup (see following section on startup test 5.2). Since (a) all rods will have been friction tested at cold conditions,

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(b) the four rods selected for additional testing will identify any problem with respect to thermal expansion, (c) the testing simplification is consistent with programs for plants before the BWR/6 product line, and (d) no failures of the hot friction test have been reported during other startup programs at other BWR/6 plants (foreign and domestic), the proposed simplification of startup test 5.1 for the Clinton Power Station is acceptable.

(4) Control Rod Drive System/Hot Single Rod Scram Testing, FSAR Subsection 14.2.12.2.5 (Startup Test 5.2)

Startup test 5.2 is concerned with testing of control rod drives under the full range of reactor operating conditions. As part of the test, rods are scram time tested after fuel loading at cold shutdown. During reactor heatup, four selected rods are time tested at various reactor pressures. Normally all rods are time tested at rated pressure and low power, and again, four rods are selected for testing during power ascension. The applicant has proposed that this sequence be modified so that the test of all rods at rated pressure and low power be replaced with a test of four rods and a test at 10 to 25% power of all withdrawn rods as part of the performance of startup test 28 at TC 2. This would result in up to 32 control rod drives not being fully tested since they would not be fully withdrawn.

GE has analyzed the reactivity worth of the scram over the insertion range of interest to transient analyses and found only a small difference in reactivity insertion between the scram of all rods and a scram in which the exempted rods and eight other assumed inoperable rods do not insert. GE has also reexamined the transient analyses of events with this reduced scram function and determined that the peak heat flux during a pressurization event does not change when the 32 CRDs are assumed to not scram.

The applicant has proposed Technical Specification changes which would exempt, for first cycle only, the 32 CRDs from scram time tests in Specification 3.1.3.2. This exemption is conditioned on all scram reactivity requirements of the plant safety analysis being met with no scram contribution from the identified rods.

The staff's review has determined that since (a) all rods will have been scram tested at cold conditions, (b) four rods will have been tested during heatup, including full pressure, and thus indicate any departure from normal trends, (c) rods will be tested at 10 to 25% power except for exempted rods, (d) analyses indicate little reactivity worth change during times important for transient analyses, and transients have been reexamined assuming no scram at all for exempted rods and eight inoperable rods and suitable operating limit maximum critical power ratio (OLMCPR) adjustments have been made to account for changes, (e) the delay of testing until 25% power is consistent with the Technical Specifications which allow operation up to 40% power following core alterations before scram time testing, and (f) suitable Technical Specifications have been proposed to exempt 32 rods and to increase OLMCPR, the proposed changes to the startup test 5.2 procedures are acceptable.

(5) Control Rod Drive System/Ganged Rod Testing, FSAR Subsection 14.2.12.2.5 (Startup Test 5.3)

The applicant has proposed deleting testing of the ganged rod mode of operation of the CRD system at cold conditions after the fuel loading. The ganged rod mode test during the preoperational phase would be retained. The acceptance

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criterion for this test requires that the control rods within a gang move together in such a way that all rods are within two notches of each other in the gang. Compliance with the criterion is demonstrated during the preoperational phase of testing. Since the ganged rod mode of operation does not serve an emergency function, the staff agrees with the applicant's position that no additional testing is required and the test may be deleted for the power ascension phase.

(6) Control Rod Sequence Exchange, FSAR Subsection 14.2.12.2.8 (Startup Test 8.0)

Control rod pattern exchanges are conducted during plant operations for the purpose of equalizing fuel assembly exposures. A demonstration test during a plant power ascension program is sometimes conducted to ensure that licensed values on core thermal limits and preconditioning interim operating management recommendation (PCIOMR) threshold power will not be exceeded during the sequence exchange. The exchanges are normally conducted at a power level between 35 and 50% of full-rated power. During the exchange, the thermal limits are continually calculated by the plant computer so that early warning may be given if critical limits are approached. On the basis of a recommendation by GE, the applicant has proposed deleting this test during power ascension testing. The proposed deletion is based on the use of generic procedures that are currently recommended by GE and which are described in the GE report NEDE-21493, "Preconditioning Interim Operating Management Recommendations (PCIOMR) Implementation Procedures," February 1982. NRC has not reviewed this report, however, the staff is aware that the subject procedures have been in use for a number of years, in both foreign and domestic BWRs. In a letter dated April 16, 1986, the applicant identified ten reactors that conducted recent startup tests wherein the control rod sequence exchange tests outlined in the PCIOMR report were used. The applicant, utilizing information collected by GE, has stated that the acceptance criteria for thermal limits (e.g., maximum critical power ratio, maximum average planar linear heat-generation rate, and maximum linear heat-generation rate) were consistently satisfied and that the sequence exchange procedures are generically applicable to the Clinton reactor. On the basis of (a) the previously successful experience with the recommended procedures and the generic nature of the procedures and (b) the use of the plant computer to closely monitor the thermal limits during later rod exchange tests through the life of the plant, the staff agrees that the additional startup test 8.0 is not required to further qualify the procedures and may be deleted.

(7) Local Power Range Monitor (LPRM) Calibration, FSAR Subsection 14.2.12.2.10 (Startup Test 11.0)

The objective of this test is to calibrate the LPRM system at several test conditions. In addition, plans currently call for verifying LPRM response during control rod movement during heatup. The applicant proposes deleting verification of the LPRM response to control rod movement during heatup and performing the response verification during TC 1. The reason for the change is to perform the response check at a sufficient power level at which most of the LPRMs have onscale, positive output.

The low-power license for Clinton will be restricted to power levels below 5% power. These low-power levels are determined by the heatup calibration of the

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average power range monitors (APRMs). The APRMs utilize input signals from the LPRM which should be properly calibrated.

Therefore, the staff finds that conducting the LPRM response test to control rod movement at TC 1 rather than during heatup is unacceptable. However, response checks can be limited to those LPRMs that have on-scale positive indications. This is consistent with the Hope Creek review of a similar proposal as documented in the staff's safety evaluation included with the staff's letter to PSE&G (March 10, 1986).

(8) Reactor Core Isolation Cooling (RCIC) System, FSAR Subsection 14.2.12.2.13 (Startup Test 14.0)

The objectives of this test are to verify the proper operation of the RCIC system over its expected operating pressure and flow ranges, and to demonstrate reliability in automatic starting from cold standby when the reactor is at power. Currently, in the course of RCIC flow testing, the RCIC controllers are tuned (adjusted optimization) at both low pressures and near rated reactor pressure. The applicant is proposing that the controller tuning at low reactor pressures be minimized.

The staff finds minimizing controller tuning at low reactor pressures acceptable on the basis of the Hope Creek review of a similar proposal as documented in the staff's safety evaluation included with the staff's letter to PSE&G (January 22, 1986).

(9) Core Power Distribution (Traversing Incore Probe (TIP) Uncertainty), FSAR Subsection 14.2.12.2.16 (Startup Test 18.0)

The objective of this test is to determine the reproducibility of the TIP system readings. The applicant proposes deleting this test from the test program based on results from other licensed BWRs which have adequately demonstrated the acceptable uncertainty of the TIP system.

The staff finds the deletion of the TIP uncertainty test acceptable on the basis of the Hope Creek review of an identical proposal as documented in the staff's safety evaluation included with the staff's letter to PSE&G (January 22, 1986).

(10) Core Power-Void Mode Response, FSAR Subsection 14.2.12.2.18 (Startup Test 21.0)

The objective of this test is to measure the stability of the core power-void dynamic response and to demonstrate that its behavior is within specified limits. The applicant proposes deleting this test from the program. The test is performed at TC 4 and 5. The applicant bases the elimination of the core power-void response test upon the inefficient signal-to-noise response of control rod oscillations in large BWR cores and its redundancy with the pressure regulator test which duplicates the stability measurements.

The staff finds the deletion of the core power-void mode response test acceptable on the basis of the Hope Creek review of an identical proposal as documented in the staff's safety evaluation included with the staff's letter to PSE&G (March 20, 1986).

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(11) (Reactor Vessel) Pressure Regulator, FSAR Subsection 14.2.12.2.19 (Startup Test 22.0)

The objectives of this test are (a) to determine the optimum settings for the (reactor vessel) pressure control loop by analysis of the transients induced in the pressure control system by means of the pressure regulators and (b) to demonstrate the takeover capability of the backup pressure regulator upon failure of the controlling pressure regulator and to set spacing between the setpoints at an appropriate value.

The applicant proposes reducing the number of test points for this test by deleting testing at TC 4 and the backup pressure regulator takeover at TC 5. These proposed deletions are based on the considerations that the pressure regulator test is performed at test conditions 1 through 6 which will bound performance at TC 4 and the backup pressure regulator takeover at TC 5. The pressure regulator test also provides stability data. The applicant is proposing monitoring stability at TC 4 by utilizing the Technical Specification surveillance required by Technical Specification 3/4.4.1, "Recirculation System," to obtain the stability data for that test condition.

The staff finds the deletion of backup pressure regulator testing at TC 5 acceptable on the basis of the Hope Creek review of an identical proposal as documented in the staff's safety evaluation included with the staff's letter to PSE&G (January 22, 1986).

In addition, the staff finds it acceptable to delete pressure regulator testing at TC 4 because the pressure regulating characteristics are adequately defined by bounding pressure regulator testing at TC 2 and 5, provided that the Technical Specification surveillance test for Specification 3/4.4.1 is incorporated in a startup test procedure to be performed at TC 4, such as the recirculation system test (FSAR Subsection 14.2.12.2.27). This later provision is to ensure that the same level of review, approval, and data evaluation of a startup procedure is applied to the surveillance procedure and results.

(12) Feedwater System, FSAR Subsection 14.2.12.2.20 (Startup Test 23.1)

The objective of the significant portion of this test is to adjust the feedwater control system for acceptable water level control. The applicant proposes deleting feedwater system testing at TC 4 on the basis of sufficient testing at TCs 2 and 5 to bound and characterize the feedwater system performance at TC 4.

TCs 2 and 5 cover the combinations of power and flows in the forced circulation regions of the power-flow map that would be encountered at TC 4. Testing and adjusting at the bracketing test conditions are sufficient to characterize performance at TC 4 without additional testing. Therefore, the staff finds it acceptable to delete feedwater system testing at TC 4.

(13) Turbine Valve Surveillance Test, FSAR Subsection 14.2.12.2.21 (Startup Test 24.0)

The objective of this test is to demonstrate the acceptable procedures and maximum power levels for surveillance testing of the main turbine control, stop, and bypass valves without producing a reactor scram. Currently, initial testing of the turbine valves - stop, control, and bypass valves - will be performed between

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TCs 2 and 3. The results of testing at these conditions will be used to extrapolate to a second test point and finally to a maximum power test condition with ample margin to prevent scramming. This testing also satisfies paragraph 5.t, RG 1.68, Revision 2, relating to demonstration of operability of the turbine control, stop and bypass valves.

The applicant proposes deleting the second measurement and extrapolation process (which determines the maximum power level) to perform turbine valve surveillance and substituting determination of a maximum surveillance testing power level on the basis of previous BWR test experience. This test change was not part of the Hope Creek review and is unique to Clinton.

The staff reviewed information from recently licensed BWRs and concluded that sufficient BWR testing experience is available to estimate a maximum power level to perform turbine valve surveillance testing. In addition, there is a substantial body of operating experience which is available from plants that have been operating for some time. Therefore, the staff finds it acceptable to utilize available BWR testing experience to establish the power level for surveillance testing for the turbine control, stop, and bypass valves rather than repeating the higher power level extrapolation process to determine the surveillance power level.

(14) Main Steam Isolation Valves (MSIVs), FSAR Subsection 14.2.12.2.22 (Startup Test 25.1)

The objectives of this portion of the test are to determine the functional performance and individual fast closure time of each MSIV at heatup and between TC 1 and TC 3 and determine the maximum power level at which full individual closure can be performed without scram. Currently, the maximum full-stroke surveillance power level is determined by closing the fastest closing MSIV at TC 2 or 3, then again at TC 5, and extrapolating the data to determine the maximum power level at which MSIV surveillance can be performed. The applicant proposes deleting the MSIV individual closure testing at TC 5 and extrapolating to determine the maximum power level for MSIV testing and substituting determination of the maximum power level for MSIV surveillance testing on the basis of previous BWR startups and operating experience.

The staff examined the maximum surveillance power level results from this test on five recently licensed BWRs. The staff concluded from the examination of these results that sufficient data are available and the results predict reasonably consistent MSIV maximum surveillance power levels. Therefore, the staff finds estimating the maximum surveillance power level from existing BWR test data rather than performing the closure test at TC 5 and extrapolating to be an acceptable alternative.

(15) Relief Valves, FSAR Subsection 14.2.12.2.23 (Startup Test 26.0)

The objectives of this test are to verify that (a) the relief valves function properly, (b) the relief valves reseat properly after operation, and (c) there are no major blockages in the relief valve discharge piping. The applicant proposes to reduce the relief valve tests to those required to ensure plant safety to minimize the potential for test-induced damage to the valves. This will be accomplished by deleting the tests during heatup at 250 psig and replacing the tests performed between TCs 2 and 3 with single valve testing at TC 1.

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The staff finds the reduced testing of the relief valves acceptable on the basis of the Hope Creek review of an identical proposal documented in the staff's safety evaluation included with the staff's letter to PSE&G (February 4, 1986).

(16) Turbine Trip and Generator Load Rejection, FSAR Subsection 14.2.12.2.24 (Startup Test 27.0)

The objective of this test is to demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator. Currently, this test is planned to be performed at three conditions during the power ascension test program. These test conditions and tests are (a) a generator load rejection during TC 2 (within the bypass capacity of the plant); (b) a turbine trip during TC 3, and (c) a generator full load rejection at TC 6. The applicant proposes changing the generator load rejection during TC 2 to a turbine trip and deleting the turbine trip during TC 3 entirely, which will simplify testing and will still conform to regulatory guidance.

The staff finds changing the generator load rejection during TC 2 to a turbine trip during TC 2 and deleting the turbine trip at TC 3 to be acceptable on the basis of the Hope Creek review of an identical proposal documented in the staff's safety evaluation included with the staff's letter to PSE&G (February 4, 1986).

(17) Recirculation Control System, FSAR Subsection 14.2.1.12.2.26 (Startup Test 29.0)

The objective of this test is to demonstrate the recirculation flow control system's capability while in the valve position (POS) mode. The applicant proposes simplifying the testing by reducing the number of intermediate flow conditions and testing inputs (ramp and step demands).

The staff finds the simplification acceptable because it does not change the test objective or summary description and the testing must still satisfy the acceptance criteria.

(18) Recirculation System Single Recirculation Pump Trip Test, FSAR Subsection 14.2.12.2.27 (Startup Test 30.1)

The objectives of this test are (a) to determine transient responses and steady-state conditions following single recirculation pump trips at selected reactor power levels and (b) to verify that the feedwater control system can satisfactorily control water level without a resulting turbine trip scram following a single recirculation pump trip. Currently, this test is performed at TC 3 and TC 6. The applicant is proposing deleting testing at TC.6 because all significant data will be obtained at TC 3 which makes TC 6 a redundant test point.

The staff examined the results of this test on recently licensed BWRs and concluded that there was little difference in results from test performance of this test at TC 3 and TC 6. Both TCs require full core flow, but differ in power levels. The test results had ample margins in meeting the acceptance criteria at both test conditions and little change with power level. Drywell piping vibration and vessel and recirculation loop temperature tests are monitored at both test conditions. Therefore, the single pump trip test at the two respective test conditions are redundant. Since TC 3 occurs earlier in the test program than TC 6, all the necessary data will be obtained at TC 3, and TC 6 can be deleted as redundant.

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On the basis of the above reasons, the staff finds deleting the single pump trip testing at TC 6 acceptable.

(19) Recirculation System Recirculation Pump Trip - Two Pumps, FSAR Subsection 14.2.12.2.27 (Startup Test 30.3)

The objectives of this test are to verify acceptable performance of the recirculation pump trip circuitry and record the resulting two-pump flow coastdown. Currently, this test is performed at TC 3. The applicant is proposing deleting this test at TC 3 and performing it in conjunction with the turbine trip and generator load rejection test, FSAR Subsection 14.2.12.2.24, at TC 6.

The acceptability of deleting the turbine trip test at TC 2 (see item 16) was based partially on performing the two-pump trip and flow coastdown at TC 3. The two-pump trip test at TC 3 will confirm the trip and flow coastdown before the generator full load rejection test is performed at TC 6.

Therefore, the staff finds the deletion of the two recirculation pump trip test at TC 3 to be unacceptable. This is consistent with the Hope Creek review as documented in the staff's safety evaluation included with the staff's letter to PSE&G (February 4, 1986).

(20) Recirculation System Recirculation Runback, FSAR Subsection 14.2.12.2.27 (Startup Test 30.4)

The objective of this test is to verify the adequacy of the recirculation runback to avoid a scram upon the loss of one feedwater pump. Currently, this test is planned to be performed at TC 3. The applicant is proposing deleting testing at TC 3 and combining this test with the feedwater pump trip test, FSAR Subsection 14.2.12.2.20 (startup test 23.3), performed at TC 6.

The staff finds combining the recirculation runback test with the feedwater pump trip test performed at TC 6 to be acceptable on the basis of Hope Creek review of the identical proposal as documented in the staff's safety evaluation included with the staff's letter to PSE&G (February 4, 1986).

(21) Recirculation System Cavitation Test, FSAR Subsection 14.2.12.2.27 (Startup Test 30.5)

The objective of this test is to verify that no recirculation system cavitation occurs on the operable region of the power/flow map. Currently this test is planned to be performed at TC 2 and TC 3 by decreasing power until a recirculation flow runback occurs and verifying that cavitation has not occurred. The applicant proposes temporarily bypassing the runback interlock while performing the test as planned, lowering the power to the analytically determined cavitation limit to determine if cavitation has occurred while confirming that the recirculation runback has been activated, without an actual runback.

The staff finds the use of a temporary bypass on the cavitation interlock to prevent actual runback while performing the recirculation system cavitation test at TC 2 and TC 3 to be acceptable on the basis of the Hope Creek review of a similar proposal as documented in the staff's safety evaluation included with the staff's letter to PSE&G (February 4, 1986). The staff notes that the Clinton test program specifies the performance of this revised test at both TC 2 and 3;

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the Hope Creek test program specifies this test only at TC 3. The conclusions with respect to acceptability of the proposed change are not affected.

Conclusion

The staff finds 19 of the proposed 21 changes to the Initial Test Program to accelerate power ascension testing for the Clinton Power Station acceptable. The two tests for which the proposed changes have been found unacceptable are:

- Startup Test 11.0 - Conducting the LPRM response test to control rod movement at TC 1 rather than during heatup. However, response checks can be limited to those LPRMs that have on-scale positive indications.

- Startup Test 30.3 - Deleting the two recirculation pump trip test at TC 3.

In addition, the applicant proposed deleting TC 4 from startup tests 22.0 and 23.1. The staff has determined that the deletion of this test condition is acceptable, provided that for startup test 22.0 the Technical Specification surveillance test for Specification 3/4.4.1 is incorporated into a startup test procedure to be performed at TC 4, such as in the recirculation system test described in Subsection 14.2.12.2.27 of the FSAR.

Preoperational Test Deferrals

The applicant, by letter dated March 12, 1986, proposed deferral of various preoperational tests with different completion milestones after fuel loading. Ten of these tests required exemptions from the General Design Criteria (GDC) and by letters dated March 27 and May 29, 1986, the applicant requested exemptions. Those preoperational tests that required exemptions and the staff's evaluation is contained in Appendix N to this supplement. An exemption from the GDC for the preoperational test deferral of the permanently installed solid radwaste system would normally be required; however, because the applicant also has a transportable radwaste system which has been determined to satisfy the GDC by the staff, no exemption is required. This deferral is discussed in Section 2.10 of Appendix N to this supplement. One of the test deferrals proposed by the applicant is related to the acceptance testing of the plant process computer historical recording services, balance of plant performance calculations, and nuclear steam supply system performance calculations. The staff has no operational requirements related to this proposed deferral; therefore, it will not be addressed. The remaining deferrals proposed by the applicant pertain to final air balancing for the auxiliary building HVAC system, the drywell cooling system, the drywell purge system, the containment HVAC system, the turbine building HVAC system, and the radwaste HVAC system. These deferrals are also discussed in Appendix N to this supplement.

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Table 14.1 Test condition (TC) region definition

TC	Power-flow map region definition
Heatup	From initial criticality until the reactor coolant system reaches 920 psig (approximately 1-2% thermal power)
1	5-20% thermal power and operating on recirculation pump low-frequency power supply (15-40% flow)
2	25-55% thermal power and 33-65% flow
3	45-80% thermal power and 80-100% flow
4	Natural circulation (approximately 50-55% thermal power and 33% flow)
5	52-80% thermal power and 38-70% flow
6	Less than or equal to 100% thermal power and within ±5% of full flow

15 SAFETY ANALYSIS

15.2 Accidents

15.2.1 Anticipated Transients Without Scram

The ATWS rule, 10 CFR 50.62, "Requirements for Reduction in Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants," requires that each boiling-water reactor (BWR) must have (1) an alternate rod injection (ARI) system that is diverse and electrically independent from the existing reactor protection system, and is designed to automatically vent the scram air header to cause control rod insertion under conditions indicative of an ATWS, (2) a standby liquid control system (SLCS) with a minimum flow capacity and boron content equivalent in control capacity to 86 gpm of 13 weight percent sodium pentaborate solution, and (3) equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS. In accordance with 10 CFR 50.62(d), the applicant, by letter dated October 16, 1985, stated that the design of the Clinton ATWS systems is complete and satisfies the requirements of the ATWS rule. This letter also stated that the installation of the ATWS systems for Clinton has been completed. This satisfies the intent of the rule for implementation before issuance of a license authorizing operation above 5% of full rated power and, therefore, is acceptable.

The staff has not completed its review of the Clinton design for compliance with the ATWS rule; however, staff review and approval is not a requirement for plant licensing. The staff is reviewing BWR generic ATWS designs, and will review the Clinton design in accordance with plant-specific review schedules. The staff's evaluation of the Clinton design will be provided in a future SER supplement.

15.2.2 Salem Anticipated Transients Without Scram (Generic Letter 83-28)

On February 25, 1983, both of the scram circuit breakers at Unit 1 of the Salem Nuclear Power Plant failed to open upon an automatic reactor trip signal from the reactor protection system. This incident was terminated manually by the operator about 30 seconds after the initiation of the automatic trip signal. The failure of the circuit breakers was determined to be related to the sticking of the undervoltage trip attachment. Before this incident, on February 22, 1983, at Unit 1 of the Salem Nuclear Power Plant, an automatic trip signal was generated based on steam generator low-low level during plant startup. In this case, the reactor was tripped manually by the operator almost coincidentally with the automatic trip.

Following these incidents, on February 28, 1983, the NRC Executive Director for Operations (EDO), directed the staff to investigate and report on the generic implications of these occurrences at Salem Unit 1. The results of the staff's inquiry into the generic implications of the incidents at Salem Unit 1 are reported in *NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant."* As a result of this investigation, the Commission (NRC) requested by Generic Letter 83-28 dated July 8, 1983, all licensees of operating reactors,

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applicants for an operating license, and holders of construction permits to respond to generic issues raised by the analyses of these two anticipated transient without scram (ATWS) events. Table 1.2 to this supplement of the SER presents the status of all Generic Letter 83-28 issues applicable to boiling-water reactors (BWRs). With the inclusion of Items 1.2 and 2.1 evaluated in this SSER, the applicant's responses to all items, except for Items 2.1, 2.2, 4.5.1, and 4.5.2, have been reviewed and found acceptable. The staff's review of Items 2.1, 2.2, 4.5.1, and 4.5.2 is ongoing. Should the staff conclude that the applicant must take additional actions to be in compliance with Generic Letter 83-28, the applicant will be notified.

In SSER 5, some of the generic concerns identified in Generic Letter 83-28 were resolved for Clinton Power Station. This SSER resolves two of the remaining concerns related to this issue.

15.2.2.1 Post-Trip Review

Data and Information Capability, Action Item 1.2

The following review guidelines, developed after initial evaluation of the various utility responses to Item 1.2 of Generic Letter 83-28, incorporate the best features of these submittals. As such, these review guidelines, in effect, represent a "good practices" approach to post-trip review. The staff has reviewed the applicant's response to Item 1.2 against these guidelines.

A. The equipment that provides the digital sequence-of-events (SOE) record and the analog time-history records of an unscheduled shutdown should provide a reliable source of the necessary information to be used in the post-trip review. Each plant variable which is necessary to determine the cause and progression of the events following a plant trip should be monitored by at least one recorder (such as a sequence-of-events recorder or a plant process computer) for digital parameters; and strip charts, a plant process computer, or analog recorder for analog (time-history) variables. Performance characteristics guidelines for SOE and time-history recorders are as follows:

   - Each sequence-of-events recorder should be capable of detecting and recording the sequence of events with a sufficient time discrimination capability to ensure that the time responses associated with each monitored safety-related system can be ascertained, and that a determination can be made as to whether the time response is within acceptable limits based on FSAR Chapter 15, "Accident Analyses." The recommended guideline for the SOE time discrimination is approximately 100 milliseconds. If current SOE recorders do not have this time-discrimination capability, the licensee [or applicant] should show that the current time-discrimination capability is sufficient for an adequate reconstruction of the course of the reactor trip and post-trip events. At a minimum, this should include the ability to adequately reconstruct the transient and accident scenarios presented in Chapter 15 of the plant FSAR.

   - Each analog time-history data recorder should have a sample interval small enough so that the incident can be accurately reconstructed following a reactor trip. At a minimum, the applicant should be able

to reconstruct the course of the transient and accident sequences evaluated in the accident analysis of Chapter 15 of the plant FSAR. The recommended guideline for the sample interval is 10 seconds. If the time-history equipment does not meet this guideline, the applicant should show that the time-history capability is sufficient to accurately reconstruct the transient and accident sequences presented in Chapter 15 of the FSAR. To support the post-trip analysis of the cause of the trip and the proper functioning of involved safety-related equipment, each analog time-history data recorder should be capable of updating and retaining information from approximately 5 minutes before the trip until at least 10 minutes after the trip.

- All equipment used to record sequence-of-events and time-history information should be powered from a reliable noninterruptible power source. The power source used need not be Class 1E.

B. The sequence-of-events and time-history recording equipment should monitor sufficient digital and analog parameters, respectively, to ensure that the course of the reactor trip and post-trip events can be reconstructed. The parameters monitored should provide sufficient information to determine the root cause of the unscheduled shutdown, the progression of the reactor trip, and the response of the plant parameters and protection and safety systems to the unscheduled shutdowns. Specifically, all input parameters associated with reactor trips, safety injections, and other safety-related systems, as well as output parameters sufficient to record the proper functioning of these systems, should be recorded for use in the post-trip review. The parameters deemed necessary, as a minimum, to perform a post-trip review that would determine if the plant remained within its safety limit design envelope are presented in Table 15.1. They were selected on the basis of staff engineering judgment following a complete evaluation of utility submittals. If the applicant's SOE recorders and time-history recorders do not monitor all of the parameters suggested in the table, the applicant should show that the existing set of monitored parameters is sufficient to establish that the plant remained within the design envelope for the accident conditions analyzed in Chapter 15 of the plant FSAR.

C. The information gathered by the sequence-of-events and time-history recorders should be stored in a manner that will allow for data retrieval and analysis. The data may be retained in either hard copy (e.g., computer printout, strip chart record) or in an accessible memory (e.g., magnetic disc or tape). This information should be presented in a readable and meaningful format, taking into consideration good human factors practices such as those outlined in NUREG 0700.

D. Retention of data from all unscheduled shutdowns provides a valuable reference source for the determination of the acceptability of the plant vital parameter and equipment response to subsequent unscheduled shutdowns. Information gathered during the post-trip review is to be retained for the life of the plant for post-trip review comparisons of subsequent events.

By letters dated May 23, 1984; October 1, 1984; and December 6, 1985, the applicant provided information regarding its post-trip review program data and information capabilities for Clinton Power Station. The staff has evaluated the applicant's submittals against review guidelines A-D, described above.

Deviations from these guidelines were discussed with representatives of the applicant by telephone on November 14, 1985, and the additional information requested was formally submitted in the December 6, 1985, letter. A brief description of the applicant's responses and the staff's evaluation of the response against each of the review guidelines follows:

A. The applicant has described the performance characteristics of the equipment used to record the sequence-of-events and time-history data needed for post-trip review. On the basis of its review of the applicant's submittals, the staff has determined that the sequence-of-events recorder and time-history recorder characteristics conform to guideline A described in this section, and are acceptable.

B. The applicant has established and identified the parameters to be monitored and recorded for post-trip review. On the basis of this review, the staff has determined that the parameters selected by the applicant include all of the parameters identified in Table 15.1 except containment (drywell) radiation. However, since this parameter is available continuously on a readout monitor in the control room as well as on the safety parameter display system (SPDS) and is also present in the emergency operations facility (EOF), the applicant's parameters conform to guideline B described in this section, and are acceptable.

C. The applicant described the means for storage and retrieval of the information gathered by the sequence-of-events and time-history recorders, and for the presentation of this information for post-trip review and analysis. On the basis of its review, the staff has determined that this information will be presented in a readable and meaningful format, and that the storage, retrieval, and presentation conform to guideline C described in this section.

D. The applicant's submittal of October 1, 1984, indicates that the data and information used during post-trip reviews will be retained in an accessible manner for the life of the plant. On the basis of this information, the staff has determined that the applicant's program for data retention conforms to guideline D described in this section, and is acceptable.

On the basis of its review of the applicant's submittals, the staff has concluded that the applicant's post-trip review data and information capabilities for Clinton Power Station are acceptable.

15.2.2.2 Equipment Classification and Vendor Interface

Reactor Trip System Components, Equipment Classification, Action Item 2.1 (Part 1)

Item 2.1 (Part 1) requires the applicant to confirm that all reactor trip system components are identified, classified, and treated as safety related as indicated in the following statement:

> Licensees and applicants shall confirm that all components whose functioning is required to trip the reactor are identified as safety-related on documents, procedures, and information handling system used in the plant to control safety-related activities, including maintenance, work orders, and parts replacement.

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The applicant responded to the requirements of Item 2.1 (Part 1) with a submittal dated October 1, 1984. In this submittal, the applicant identified two sets of components that had not previously been classified as safety related during the review of the classification of components required to trip the reactor. One, the main steamline isolation valve limit switches, was classified as safety related and the other, the backup scram valves, remained classified as non-safety related since the staff had accepted the non-safety classification of these valves. The applicant also verified that activities that affect any safety-related components are classified as safety related. However, when parts that are subcomponents are being procured, they may not have had their classification predetermined. In such case, the parts are classified according to the classification criteria and are entered on the Q-list.

The staff's evaluation is based on the results of the review of this item performed by its contractor EG&G Idaho. The Technical Evaluation Report prepared by EG&G Idaho is contained in Appendix L of this SSER. Based on the review of EG&G's findings, the staff concludes that applicant's statements confirm that a program exists for identifying, classifying, and treating components that are required for performance of the reactor trip function as safety related. This program meets the requirements of Item 2.1 (Part 1) of Generic Letter 83-28, and is, therefore, acceptable.

Table 15.1 BWR parameter list

SOE recorder	Time-history recorder	Parameter/signal
x		Reactor trip
x		Safety injection
x		Containment isolation
x		Turbine trip
x		Control rod position
x (1)	x	Neutron flux, power
x (1)		Main steam radiation
(2)	(2)	Containment (drywell) radiation
x (1)	x	Drywell pressure (containment pressure)
(2)	(2)	Suppression pool temperature
x (1)	x	Primary system pressure
x (1)	x	Primary system level
x		MSIV position
x (1)		Turbine stop valve/control valve position
x		Turbine bypass valve position
	x	Feedwater flow
	x	Steam flow
(3)	(3)	Recirculation; flow, pump status
x (1)		Scram discharge level
x (1)		Condenser vacuum
x		AC and DC system status (bus voltage)
(3)(4)	(3)	Safety injection; flow, pump/valve status
x		Diesel generator status (on/off, start/stop

(1) Trip parameters.

(2) Parameter may be recorded by either an SOE or a time-history recorder.

(3) Acceptable recorder options are: (a) system flow recorded on an SOE recorder, (b) system flow recorded on a time-history recorder, or (c) equipment status recorded on an SOE recorder.

(4) Includes recording of parameters from all the following systems: HPCS, LPCI, LPCS, and RCIC.

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17 QUALITY ASSURANCE

17.5 Independent Design Verification

17.5.1 Background

Bechtel Power Corporation (Bechtel) was engaged by the applicant to conduct an independent design review (IDR) of the Clinton Power Station, Unit No. 1 (Clinton). The purpose of the IDR was to assess the adequacy of the Clinton design through a review of the design process employed. Specifically, evaluation of plant design work measured the adequacy of

(1) implementation of design commitments and criteria

(2) technical adequacy of design

(3) structure and implementation of the design process, particularly with regard to compliance with the applicant's commitments to the provisions of Regulatory Guide (RG) 1.64 and ANSI Std. N45.2.11

A program plan was proposed by Bechtel and commented on by the staff in a letter sent to the applicant on August 6, 1984. Other interested parties including the applicant and the Attorney General of the State of Illinois commented, too. A revised program plan was subsequently submitted and it was approved by the NRC. Bechtel issued a final IDR report on this program in January 1985.

Bechtel commenced the IDR in August 1984. The NRC closely monitored conduct of the IDR including:

(1) attendance at public meetings in Rosemont, Illinois, on September 16 and November 13, 1984, to review IDR progress;

(2) inspection of IDR activities at Bechtel headquarters in San Francisco, California, on October 18 and 19, 1984 (preceded by a tour of the Clinton site on October 17, 1984). [The NRC's report of this inspection was provided in a letter to the applicant dated November 6, 1984. Bechtel replied to the NRC inspection report in a letter dated November 12, 1984 (for programmatic items), and in the final IDR report (for technical items).];

(3) monitoring of a large number of telephone conversations between Bechtel, the applicant, and Sargent & Lundy Engineers (S&L), during which observations or other technical matters were discussed;

(4) attendance at a public meeting in Chicago, Illinois, on March 7, 1985, where a presentation on the final IDR report was given by Bechtel; and

(5) followup inspections at Bechtel after issuance of the final IDR report (March 26 through 28, 1985) where documentation supporting Bechtel's conclusions was reviewed and evaluated, and at S&L (May 6 through 9, 1985) where the adequacy and status of corrective actions were reviewed and evaluated.

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17.5.2 Bechtel Design Review Program

Bechtel performed two types of reviews, vertical and horizontal. The vertical review examined the design of the shutdown service water (SSW) system, the portion of the high-pressure core spray (HPCS) system inside containment, and the Class 1E ac electrical distribution system. The vertical review also went beyond these systems in evaluating various common design requirements such as high-energy-line break, fire protection, and seismic interactions. The horizontal review was based on applicable findings from design audits of other stations including Byron, LaSalle, and Fermi, as well as prior applicant audits of Clinton.

Bechtel reviewed more than 2900 documents in a period of more than 6 months, expending approximately 31,000 man-hours in the process. Where problems or concerns were identified, a potential observation report was issued. A total of 84 potential observation reports were issued, of which 76 were determined to be valid and 8 were classified as invalid. The final IDR report provided technical details on each observation report (both valid and invalid), including resolutions and, in certain cases, planned corrective actions. The IDR report also analyzed trends which appeared to be generic to the design process, drawing conclusions as to the significance of each identified trend.

17.5.3 Bechtel Conclusions

Bechtel reached conclusions about the adequacy of the design and design process at Clinton relative to both the systems reviewed and the overall plant. The IDR report set forth Bechtel's conclusions in considerable detail, including the bases for these conclusions. The IDR conclusions assumed successful completion of work committed to in resolving issues raised by the review. Contingent on completion of the work, Bechtel concluded that there was reasonable assurance that the overall design of Clinton was technically adequate and met FSAR commitments. Furthermore, Bechtel stated that more review work would, in all likelihood, produce results similar to those from the IDR, i.e., there would be more observations, but they would be of comparable number and significance.

17.5.4 Assessment by the NRC Staff

The NRC staff has assessed the results of the IDR including a detailed review of the subsequent corrective actions, both completed and in progress. As a part of the staff's assessment, two inspections were conducted, one at the Bechtel offices in San Francisco to review the documentation supporting the conclusions of the IDR team and the other at the S&L offices in Chicago to review S&L implementation of corrective actions. The inspection at Bechtel focused on the review of documentation submitted to Bechtel by S&L that formed the basis for the IDR team's agreement that an observation report required no corrective action. In addition to reviewing documentation connected with specific observation reports, the review sheets in the areas of fire protection and seismic Category II/I were inspected. Both of these reviews appeared to be comprehensive and well documented. The Appendix R (10 CFR 50) safe shutdown analysis prepared by S&L was also reviewed. Although this analysis was out of date, the staff concurs with the conclusion of the IDR team that the methodology used by S&L could ensure that the safe shutdown capability would be maintained in the event of fire.

Through inspection of Bechtel, the staff found the IDR to be well documented. It was also evident by reviewing the checksheets prepared by the individual

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reviewers that the IDR team had reviewed in detail the S&L documentation. On the basis of its review of the IDR report and subsequent inspection of the supporting documentation, the staff concurs in the findings of the IDR team and concludes that observation reports that were subsequently found acceptable by the IDR team based on review of additional information provided by S&L are closed. The observation reports in this category are: OR-6, 8, 15, 16, 18, 22, 23, 25, 26, 27, 31, 32, 36, 37, 38, 40, 44, 45, 47, 50, 52, 53, 56, 58, 60, 61, 62, 65, 66, 76, and 77. OR-51 was closed by the Bechtel IDR team and was subsequently closed by the staff after receipt of the applicant's confirmatory letter dated February 5, 1986, that corrective action had been completed. This item is further discussed in Section 17.5.4.2 under the heading "Mechanical Discipline."

The purpose of the staff's inspection at S&L was to review the implementation of corrective actions agreed to with Bechtel to resolve concerns generated during the IDR. Of the observation reports requiring corrective actions, 21 of these resulted in changes to the FSAR and are addressed in Section 17.5.4.1. The corrective actions associated with the remaining observation reports were reviewed during this inspection. At the time of the staff's inspection, the corrective actions associated with 11 observation reports were still in progress. However, these had progressed to a point where the staff was able to review them in sufficient detail to conclude that they would be completed as agreed on with Bechtel. Therefore, no further reinspection of S&L is necessary. The corrective actions for these 11 observation reports (OR-5, 9, 13, 54, 55, 57, 64, 73, 74, 80, and 81), all in the mechanical discipline, are discussed in Section 17.5.4.2. The corrective actions for the observation reports that were completed at the time of staff inspection were reviewed and appeared to have been completed as agreed on with the IDR team.

Observation reports requiring corrective actions were held open until receipt of a confirmatory letter from the applicant that the corrective actions had been completed and adequately resolved the concerns of the IDR team. Detailed discussions of the staff's assessment of the individual observation reports and the trends noted by Bechtel are discussed below.

17.5.4.1 FSAR Changes

Twenty-one observation reports involved commitments from the applicant to submit proposed FSAR changes to the NRC. (The observation reports in this category are: OR-4, 7, 12, 14, 17, 24, 30, 43, 46, 48, 55, 57, 63, 64, 69, 70, 72, 73, 75, 79, and 83). Proposed FSAR changes constitute open licensing issues to be resolved between the applicant and the staff. Since these items are individually resolved as licensing issues, they were considered closed for purposes of the IDR when they were formally submitted to the staff. All 21 proposed FSAR changes have been submitted and all are closed. OR-4, 7, 12, 14; 17, 30, 46, 48, 63, 72, 75, and 83 were closed on the basis of letters from the applicant to the staff dated May 29 and June 7, 1985. OR-24, 43, 69, 70, 73, and 79 were closed on the basis of the applicant's letter to the staff dated November 26, 1985. The three remaining observation reports (OR-55, 57, and 64) were closed on the basis of the applicant's letter to the staff dated February 5, 1986.

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17.5.4.2 Technical Assessments

The following is the NRC staff's technical assessment of the valid observation reports.

Mechanical Discipline

There were 9 valid observation reports in the mechanical systems area and another 27 valid observation reports in the area of mechanical components. These 36 observation reports can be further broken down into three categories: (1) those which were closed by the IDR team based on the response by S&L and which required no action by S&L; (2) those observation reports requiring corrective action by S&L for which corrective action appeared to be completed; and (3) the observation reports for which the corrective actions accepted by the IDR team were still in progress. The following NRC staff comments are provided on these observations.

OR-5 identified that the equipment qualification packages for two active valves had not addressed valve operability under seismic loadings. Also, S&L calculations were needed to demonstrate that the vendor's allowable deflections would not be exceeded under the seismic loadings. In addition, engineering judgments associated with S&L's review of equipment qualification packages needed to be documented. To resolve this issue and the generic equipment qualification concern, S&L developed a new updated checklist and committed to include it in all the equipment qualification packages. At the S&L offices, the staff was informed that 75% of the 510 total equipment qualification packages had been completed. The staff reviewed the completed checklist and was satisfied that the aforementioned concerns were being adequately resolved by use of the updated checklist. This observation report was closed by the staff after receipt of the applicant's letter dated November 26, 1985, confirming that all the equipment qualification packages had been completed and revised.

OR-9 identified that specific piping support weld sizes did not comply with the requirements of ASME Code Section III and AWS Std. D1.1 which are committed to in the Clinton FSAR. Specifically, the subject pipe support weld sizes were smaller than the weld sizes required by the two aforementioned codes based upon the thicker of the two parts being joined. S&L has initiated a request for a Code case to allow weld sizes less than those as required in Appendix XVII, paragraph XVII-2452.1 of ASME Code Section III. Also, a review of the weld procedure qualification is being made to ensure that all welds were made in accordance with qualified welding procedures. The staff verified at the S&L offices in Chicago that the welding procedure qualification had been completed for full and partial penetration welds which were not prequalified per AWS Std. D.1.1. This issue was closed by the staff after receipt of the applicant's confirmatory letter dated November 26, 1985, that documented acceptance of the Code case by the NRC, confirmed all associated welds have been made in accordance with approved welding procedures, and confirmed that associated design documents had been updated accordingly.

OR-13 identified a concern regarding whether an adequate program was in place to verify pipe rupture restraint hot gaps. At S&L, the staff reviewed a draft Preoperation Test Procedure and verified that this procedure, if properly implemented, would present an adequate program for verification of rupture restraint hot gaps. This draft procedure applies to all rupture restraints including those designed by S&L as well as by General Electric. The staff also verified

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that the draft procedure includes an adequate reconciliation aspect for hot gaps that are too large. This observation report was closed by the staff after receipt of the applicant's letter dated February 5, 1986, confirming that a hot gap verification program had been established.

OR-19 addressed a concern regarding the replacement of specific snubbers with rigid restraints (i.e., rods, struts, or structural steel) and the resulting impact on equipment nozzles and pipe supports. S&L performed an evaluation which documented that the effect of snubber replacement and thermal movements on equipment nozzle allowables was acceptable. During an inspection at Bechtel from March 26 through 28, 1985, the staff verified Bechtel had reviewed the aforementioned calculations and had appropriately assessed the observation. Also, during an inspection at S&L from May 6 through 9, 1985, the staff reviewed the snubber replacement program. Of the 375 snubbers in the original design of Clinton, 227 snubbers had been replaced with rigid restraints to date. The staff also found that S&L's snubber replacement program was developed with Region III's involvement and is documented in Welding Research Council Bulletin 300 under the paragraph entitled "Zero Deflection Criteria." The staff concluded that the program properly addresses the replacement of snubbers with rigid restraints. This observation report was closed by the staff after receipt of the applicant's letter dated November 26, 1985, confirming that all affected stress reports had been updated to reflect snubber replacement.

OR-25 questioned whether the modeling of motor-operated or air-operated valves with extended masses resulted in a more rigid representation of the valve because of improper consideration of amplification through the valve superstructure. At the time the IDR was being conducted, there were no flexible valves identified. As indicated by the applicant in its March 21, 1985, letter, there are approximately 30 flexible valves. The staff reviewed the S&L program for qualifying these valves during its inspection of S&L in May 1985. The staff concluded that S&L has an adequate program in effect, based on staff review of an S&L-conducted generic study. Representative piping systems were analyzed using detailed finite element models of the valves which accounted for flexibility. The results of the study were compared with similar cases in which the valves were modeled as rigid in the piping analysis. Amplification factors resulting from this comparison were used to evaluate the flexible valves. S&L used the results of this study to qualify the flexible valves. The staff concurs with the process in use by S&L to qualify flexible valves, and considers this observation report to be closed. While reviewing the corrective action associated with this observation report, the staff noted that the S&L stress analysis group is not addressing the effects of valve flexibility in its mathematical model for calculating pipe stress. This issue was identified as a deviation from a licensing commitment and was satisfactorily resolved by the staff in SSER 5, Section 3.9.2.

OR-27 identified that the bus tie dimension between the battery racks (Division I, 125-V dc) is greater than what was specified on the design drawings. Consequently, the seismic qualification of the batteries did not address the as-built bus tie length. To address this concern, S&L performed a calculation. The staff reviewed this calculation and verified that it supported the seismic qualification of the batteries. The staff was also concerned about the generic implication that the as-built configuration, in general, did not agree with the design documents. To address this as-built/design discrepancy, the staff reviewed "Environmental/Seismic Qualification Field Verification Program," PI-CP-050, Revision 0, dated April 19, 1984, and verified that the applicant's

program would have probably identified the aforementioned specific concern had it not been otherwise identified. Thus, the staff was satisfied that the specific resolution for the batteries had been properly analyzed and that a program is in place to adequately resolve similar discrepancies.

OR-36 questioned the program in effect for the Clinton project relative to protection of safety-related equipment from damage resulting from interactions with other equipment, safety related or not safety related, during seismic events. Although the IDR accepted the specific resolution to the questions raised, the staff was concerned with broader questions in this area. During the staff's inspection at S&L on May 6 through 9, 1985, it reviewed the key calculation and project instruction documents of the Clinton design relative to the subject of seismic interaction analysis. The staff is satisfied that the program for seismic interaction analysis at Clinton is satisfactorily structured to adequately satisfy requirements in this area. No further action is required. This observation report is considered closed.

OR-51 resulted from the field walkdown which discovered 1½-inch gaps between Division I and Division II batteries and the battery rack end rails. S&L performed a calculation which demonstrated that the battery cells would not impact the end rails during a seismic event. However, there is enough uncertainty in some assumptions of the calculation to raise questions about the margin in the calculation. In view of these uncertainties, the applicant eliminated the gaps altogether. This observation report was closed on the basis of the applicant's letter dated February 5, 1986, confirming that corrective action had been completed.

OR-54 expressed a concern that the documentation package used to accept qualification of the diesel generators appeared to lack adequate justification for seismic qualification. However, Bechtel accepted the S&L response which demonstrated that S&L had been involved in an ongoing qualification program for the diesel generators. At S&L, the staff reviewed an S&L calculation that confirmed the validity of an assumption made by the diesel generator manufacturer regarding anchor bolt modeling. The staff was satisfied with the approach being taken regarding diesel generator qualification, and this observation was closed by the staff after receipt of the applicant's letter dated November 26, 1985, confirming that the subject qualification has been satisfactorily completed.

OR-55, 57, 64, and 73 all involve design considerations relative to high-energy-line-break (HELB) and moderate-energy-line-break (MELB) effects. In each of these observation reports, the IDR determined that the S&L documentation was not sufficient to enable the IDR team to conclude that HELB/MELB effects had been adequately considered in all cases. Since publication of the IDR report, S&L has done a substantial amount of work to document its efforts in these areas. During its inspection of S&L on May 6 through May 9, 1985, the NRC staff reviewed a portion of the preliminary information prepared by S&L and determined that this documentation was sufficiently complete to permit meaningful evaluation. Subsequently, the applicant had an independent review performed relative to the HELB/MELB design at Clinton and provided the results of the review to the NRC staff. These observation reports were closed by the staff after receipt of the applicant's letters of November 26, 1985 (OR-73) and February 5, 1986 (OR-55, 57, and 64) which confirmed that this information had been forwarded to the staff for review as part of the normal licensing process. The staff's review and acceptance of the resolution of OR-55, 57, 64, and 73 is addressed in Section 3.6.1 of this supplement to the SER.

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OR-74 represented a concern that calculations or analyses confirming the ability of certain check valves to operate during and after a seismic event were not available. S&L provided a deflection analysis which justifies operability of the valves on the basis of certain actuator deflections. The valve supplier stated that the check valve would remain operable regardless of the deflections. S&L committed to obtaining documentation in the form of a seismic analysis of the valve from the vendor in order to document this position. This observation report was closed on the basis of the applicant's letter dated February 5, 1986, confirming that corrective action has been completed.

OR-80 identified a concern that the FSAR commitment to design pressure-retaining components in the ESF systems to include a corrosion allowance had not been fully implemented. In resolving this concern, Bechtel concluded that S&L's response provided adequate justification that the FSAR commitment had been implemented. However, two valves were identified that needed their Code Data Package sheets updated to properly document that the Code minimum wall thickness requirements had been met. During the staff's inspection at the S&L offices, it was verified that S&L had initiated the corrective action by requesting the valve manufacturer to update the subject data sheets. This observation report was closed by the staff after receipt of the applicant's letter dated November 26, 1985, confirming that the associated Code Data Package sheets have been corrected.

OR-81 expressed a concern that the seismic equipment qualification for the shutdown service water system pumps did not adequately demonstrate pump operability during a seismic event. In response, S&L stated that it had evaluated the pump vendor's seismic analysis and determined that the effects were insignificant. However, to confirm and document its initial assessment, S&L performed a calculation which Bechtel subsequently accepted as resolving the specific concern. To ensure that all similar concerns are adequately addressed, S&L is updating all seismic qualification reports to include a new equipment qualification (EQ) checklist. The new EQ checklist requires that equipment deflections at critical sections be compared against allowables for active components for which analysis is used as a basis of qualification. During its inspection of S&L, the staff reviewed S&L's confirmatory calculation as well as S&L's new EQ checklist and was satisfied that both were adequate. However, this observation report was closed by the staff after receipt of the applicant's letter dated November 26, 1985, confirming that all associated EQ packages have been updated to include the new EQ checklist and to document engineering judgments.

The remaining 20 observation reports in the mechanical discipline were not specifically addressed in this supplement because they either required no corrective action or were generally deemed to be of lesser safety significance and corrective actions appeared to be completed. The staff concurs that those 13 which were resolved by the IDR team based on the S&L response and which required no corrective action are closed. These 13 observation reports are: OR-16, 18, 22, 23, 26, 40, 44, 45, 47, 52, 53, 56, and 58. The remaining 7 observation reports (OR-20, 21, 39, 43, 67, 69, and 84) in the mechanical discipline that required S&L corrective actions were reviewed by the NRC staff and the staff concurs that the corrective actions when completed will adequately resolve the concerns of the IDR team. Although the corrective actions for these observation reports appeared to have been completed during the staff's May inspection of S&L, these reports were held open pending a confirmatory letter from the applicant verifying that the corrective actions have in fact been acceptably completed and resolve the concerns of the IDR team. These observation reports were closed

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by the staff based on the applicant's letter dated November 26, 1985, confirming the corrective action had been completed.

Electrical Discipline

There were 17 valid observation reports in the electrical power and instrumentation and controls areas. Some of these have been resolved by the IDR team on the basis of the S&L response; the rest required corrective action. The following NRC staff comments are provided on these observations.

OR-6 involved starting voltages at the terminals of continuous-duty motors and motor-operated valve (MOV) operators during simultaneous start of non-running engineered safety feature loads on offsite power when a LOCA occurred. Since starting voltages had not been calculated, the IDR team was concerned that motors and MOVs could stall and draw high inrush current that could cause the thermal overload protection to trip. S&L performed confirmatory calculations to verify the ESF motors required to function upon actuation by a safety signal would perform their safety function. These calculations were reviewed and accepted by the IDR team. In addition, the IDR team performed an independent calculation to verify the 460-V motor acceleration. This was identified as the most restrictive condition. The IDR team calculation provided an additional level of confidence in the S&L calculation. During the inspection of IDR documentation at Bechtel on March 26, 1985, the staff reviewed the S&L confirmatory calculation. The staff verified that the S&L calculation confirmed that the 460-V ESF motors will not be tripped by their respective circuit breakers during the acceleration period. In view of the S&L calculation, the IDR team's independent calculation, and the staff's review of the entire matter, the staff concurs that the functionality of the ESF motors has been adequately demonstrated and concurs with the IDR's conclusion that this item be closed.

OR-10 was initiated because certain noncritical diesel generator trip circuits were not bypassed during a LOCA condition (coincident with a loss of offsite power) for a 10-second interval. This observation resulted in the modification to the diesel generator bypass circuitry to provide a noninterruptible power supply to the bypass relays. Although the concern violated an FSAR commitment, the IDR concluded this was not a safety-significant condition because the noncritical trips were Class 1E devices, therefore failure of one trip could only affect one diesel generator, and hence the diesel generators met the single-failure criterion. Nevertheless, S&L proceeded to review 102 additional auxiliary relay circuits to determine whether similar problems existed in other circuits. This review questioned whether noninterruptible power should be provided to relays used to shed a small number of non-Class 1E loads from the Class 1E buses during the transition from offsite to onsite power. S&L performed a calculation which demonstrated that the design was adequate since these loads would be shed within approximately 5 cycles of reenergizing the buses with onsite power and a faulted condition of one of the non-Class 1E loads did not have an adverse effect on the bus. The staff reviewed the calculation and found it acceptable. The staff considers the work done in this area to be sufficient; and the observation report was closed on the basis of the applicant's letter dated February 5, 1986, confirming that corrective action had been completed.

OR-11 raised questions of electrical separation, including questions relative to bundling of Class 1E cables with non-Class 1E cables in several panels in General Electric's (GE's) design scope. In each instance within S&L's scope

of design responsibility, S&L provided documentation or justification that resolved the IDR team's concern. The concern about separation in the GE panels was referred to GE for review. Subsequently, on the basis of a probabalistic analysis and a failure-modes-and-effects analysis, GE determined that no safety hazard existed, During the inspection of S&L on May 10, 1985, the staff reviewed the GE analysis. The staff concluded that the GE analysis satisfactorily demonstrated that an electrical fault in these panels would be cleared by the circuit protection device with no degradation to Class 1E circuitry. This observation report was closed by the staff after receipt of the applicant's confirmatory letter dated November 26, 1985.

OR-33 and 34 both involved inconsistencies within equipment qualification packages between vendor qualification information and S&L's certification of the components for service in extreme environments. In resolving these issues, the applicant committed to reviewing the section of the environmental qualification checklists for all Class 1E packages to ensure that these particular areas were properly addressed. During its inspection at S&L in May 1985, the NRC staff reviewed the work performed in regard to this commitment and found it to be satisfactory. The staff considers these items to be closed on the basis of the applicant's letters dated November 26, 1985 (for OR-33), and February 5, 1986 (for OR-34), confirming that corrective action had been completed.

OR-60 involved several potential deficiencies relative to the voltage of various components of the SSW system. The IDR team raised the concerns that the stall time on MOV actuators might not be adequate for overload protection of thermal magnetic breakers; the "hammer-blow" effect for MOV operation might not be as effective for MOV operation during the reduced voltage condition; and that there was a possibility that the source side undervoltage relay would trip the offsite power supply breaker. S&L subsequently provided analyses and calculations which, together with the response to OR-6 (described above), satisfied the IDR team's technical adequacy concerns. During the review of IDR documentation at Bechtel headquarters on March 26, 1985, and the review of S&L on May 9, 1985, the staff reviewed these calculations and associated matters. As a result of the review of OR-60 and 6, the staff concurs with the IDR team's conclusion that the question of technical adequacy of the design has been fully resolved. This item is considered closed.

OR-76 noted that the maximum calculated momentary symmetrical short-circuit current that could exist at the 4160-V, Class 1E switchgear, when the reserve auxiliary transformer is supplying LOCA loads, exceeded the ANSI-rated capacity. The observation report represented a concern that the rated momentary duty of the switchgear did not meet design requirements under short-circuit conditions. S&L provided a Westinghouse-certified test result which demonstrated that the momentary duty of the switchgear was greater than the calculated value and, therefore, even though the ANSI rating was exceeded, the breaker capacities were suitable for use at Clinton. The IDR team accepted this response and considered the item closed. During the visit to Bechtel in March 1985, the staff reviewed the documentation supporting the IDR team's conclusion and concurred with the IDR that the adequacy of the switchgear had been satisfactorily demonstrated. This item is considered closed.

OR-77 involved the fast transfer of power source from one offsite source to the second offsite source at the Class 1E, 4160-V buses. The IDR team's concern was that the length of bus dead time was excessive and the degradation of bus

voltage could possibly cause the application of more than normal starting forces to coil ends and other components of Class 1E motors, possibly resulting in motor trip under certain faulted conditions. S&L subsequently provided an analysis which demonstrated that the motors were not overstressed during the transfer. The results of the analysis were accepted by the IDR team. During the visit to Bechtel in March 1985, the staff reviewed the file of documentation relating to this observation report. As a result of its review, the staff concluded that Bechtel had sufficient technical basis to accept the resolution presented by S&L. This item is considered closed.

The nine remaining observation reports in the electrical discipline were not specifically addressed in this supplement because they either required no corrective action or were generally deemed to be of lesser safety significance and corrective actions appeared to be completed. The staff concurs that those four which were resolved by the IDR team on the basis of the S&L response and which required no corrective action are closed. These four observation reports are OR-8, 31, 32, and 50. The remaining five observation reports in the electrical discipline that required S&L corrective action were reviewed by the staff and the staff concurs that the corrective actions when completed should adequately resolve the concerns of the IDR team. Although the corrective actions for these observation reports appeared to have been essentially completed at the time of the staff's May inspection of S&L, these observation reports were held open pending a letter from the applicant confirming that the corrective actions have in fact been acceptably completed and resolve the concerns of the IDR team. The remaining five observation reports in the electrical discipline requiring confirmation by the applicant regarding completion of corrective actions were closed by the staff on the basis of the applicant's confirmatory letters dated November 26, 1985 (OR-28, 59, and 62), and February 5, 1986 (OR-1 and 29).

Structural Discipline

There were eight valid observation reports in the structural area. All of these observation reports were resolved by the IDR team on the basis of the S&L response and required no corrective action. The following NRC staff comments are provided on these observations.

OR-15 identified a discrepancy in tornado pressures between the structural design criteria and the calculations for the circulating water screenhouse structure. Investigation of this matter revealed the design criteria had been incorrectly changed in 1984 and that the calculation was correct. The staff has reviewed this matter and concurs with the IDR team's conclusion that the design is adequate. This item is considered closed.

OR-38 involved a discrepancy between the calculations and drawings related to pipewhip restraint FWR11. The drawings indicated there were two 1½-inch-diameter rods; the calculation, however, considered two 1-inch-diameter rods. The results of the calculation indicated a total strain of 85% of ultimate strain which was considered excessive compared with the structural design criterion strain of 50% of ultimate. A corrected calculation using the installed 1½-inch-diameter rods indicated a strain of 19% of the ultimate strain. The staff considers the technical resolution of this item satisfactory. This problem appears to have been random in nature and the staff does not consider additional action warranted. This item is considered closed.

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OR-61 was related to use of the square root of the sum of the squares (SRSS) method for combining dynamic soil pressures with other seismic effects. If the SRSS method were not applied, a safety factor below 1.1 would be calculated. S&L considered the SRSS method to be valid because of a comparison of frequencies of the structure and a soil column which S&L indicated were out of phase. The IDR team did not agree with S&L's position but noted conservatisms such as soil resistance from the pond side of the structure were neglected in the calculation and inside hydrodynamic pressure was assumed to act on the structure at the opening to the pond. The staff has reviewed this matter and concurs with the position taken by the IDR team that the overall calculation is conservative. The staff considers the design to be adequate and no further action is required on this item. This item is considered closed.

OR-71 involved discrepancies in the circulating water screenhouse design between a design calculation and the requirements of ACI Code 318-71. The observation report represented a concern that the foundation design of the screenhouse did not meet Code requirements. S&L provided the IDR team with documentation substantiating the adequacy of the screenhouse basemat reinforcing steel layout and demonstrating that the basemat design satisfied all Code requirements. Subsequently, after review of additional documentation, the IDR team accepted the S&L resolution. During the visit to Bechtel in March 1985, the staff reviewed the documentation supporting the IDR team's acceptance of the resolution. The staff considers this observation report to have been largely a matter of interpretation of ACI Code requirements and considers that S&L has demonstrated compliance with the Code. OR-71 was closed by the staff after receipt of the applicant's confirmatory letter dated November 26, 1985, that the structural design criterion had been updated.

With regard to the four remaining observation reports (OR-37, 62, 65, and 66) in the structural discipline, the staff concurs with the IDR team's acceptance of the resolution of these items. The staff considers these items closed. These reports were not specifically addressed because no corrective actions were required and these are deemed to be of lesser safety significance.

17.5.4.3 Invalid Observation Reports

Eight observation reports (OR-2, 3, 35, 41, 42, 49, 68, and 78) were classified by the IDR team as invalid. The staff has reviewed these observations and concurs with the IDR classification.

OR-49 and 68 were classified as invalid because they were beyond the scope of the IDR. Specifically, these items resulted from the plant walkdown but were determined to be construction deficiencies as opposed to design deficiencies. The IDR report indicates that these items have been turned over to the applicant for correction or resolution. During the public meeting in Chicago on November 13, 1984, a representative of the applicant stated for the public record that construction deficiencies of this nature were included in the applicant's tracking system for correction or resolution. Consequently, these two observations are left for verification by NRC Region III personnel, on a selected basis, in accordance with their normal procedures for verifying correction of construction deficiencies.

17.5.4.4 Common Design Aspects

In addition to the specific systems reviewed by the IDR team, the IDR team evaluated the design and design process of certain common design aspects, such as high-energy-line break (HELB), moderate-energy-line break (MELB), seismic interactions (seismic Category II/I), and fire protection. In the areas of seismic Category II/I and fire protection, the IDR team concluded that although the design work in these areas was still in progress at the time of review, the portion of work completed was acceptable. The IDR team further concluded that the design basis for fire protection and seismic Category II/I were well documented by S&L and that procedures would ensure that these design aspects were adequately completed. During the staff's followup inspection of Bechtel on March 26 through 28, 1985, the documentation in the areas of seismic Category II/I and fire protection was found to fully support the IDR team's conclusion regarding the design process and design adequacy for these design attributes. Bechtel's conclusions for these common design aspects does not suggest the need for further review in this area, except as noted below for HELB/MELB. When specifically questioned by NRC staff at the public meeting in Chicago on March 7, 1985, the Bechtel engineer responsible for the review of common design aspects stated for the public record that these design aspects had generally been performed in a satisfactory manner and that the number of observation reports in this area was not unusual.

In the case of HELB/MELB, Bechtel observed that a significant amount of work had been performed but the documentation of the work was insufficient to allow Bechtel to arrive at definitive conclusions regarding the adequacy of the HELB/MELB design. The IDR team generated four observation reports, OR-55, 57, 64, and 73, dealing with different aspects of the HELB/MELB issue. These are:

(1) the effects of pipewhip and jet impingement on safety-related equipment located outside the drywell, OR-55

(2) the spray effects on safety-related equipment caused by a postulated piping failure, OR-57

(3) the flooding effects on safety-related equipment caused by a postulated piping failure, OR-64

(4) the effect of pipewhip and jet impingement on safety-related equipment located inside the drywell, OR-73

To resolve these observation reports, S&L has committed to:

(1) provide a documented analysis in each of the four areas that will contain enough detail to allow an effective independent review of design adequacy

(2) revise the FSAR to update commitments and reflect the results of all analyses

(3) implement an effective design change control program to ensure that future design changes will be evaluated for their effects on safe shutdown

Since the IDR team was unable to reach a conclusion regarding design adequacy in the four HELB/MELB areas noted above, the applicant has committed to provide an independent assessment of these areas to the NRC staff.

The FSAR changes addressing OR-55, 57, and 73 have been submitted to the staff for review. During its inspection of S&L corrective actions, the staff noted design change control procedures in place to ensure that future design changes will be evaluated for their effects on safe shutdown. The staff review of the independent HELB/MELB assessment and the FSAR changes were conducted as part of the licensing process.

With the applicant's commitment to independently review the HELB/MELB design, the staff finds that the subject of common design aspects has been thoroughly reviewed and is considered closed for purposes of the IDR. There is sufficient confidence that, with the exception of HELB/MELB, the common design requirements have been adequately addressed in the plant design. The HELB/MELB assessment was submitted to the staff via the applicant's letter dated September 30, 1985, and is considered closed for the purpose of the IDR. The staff's review of OR-55, 57, 64, and 73 is addressed in Section 3.6.1 of this supplement to the SER.

17.5.4.5 Trend Analysis

The IDR report identified a number of trends which appeared to be generic to the design process at Clinton. The IDR concluded that these trends were not of a nature to alter the judgment that the design process at Clinton was adequate. Nevertheless, in a letter dated March 21, 1985, the applicant committed to certain actions to eliminate these trends. The NRC staff reviewed these corrective action programs during its inspection at S&L in May 1985. The staff determined that the corrective action committed to by the applicant was being implemented in a satisfactory manner. The staff will monitor the programs to rectify trends on a continuing basis. The nature of these trends does not suggest the need for further review and, as such, the corrective actions indicated below are being applied on a forward-fit basis. The following paragraphs provide the staff's specific comments on these trends.

Documentation of Engineering Judgment

The IDR team found a significant number of situations where it believed S&L judgments were not appropriately documented, or where documentation left some doubt about the ability of an independent reviewer to reach the same conclusions as S&L. In these cases, S&L was usually requested to perform additional checking of the design or to perform check calculations to confirm the design concept and intent and otherwise more fully document the design process.

Sargent and Lundy has recognized the need for improvements in the area of documentation of design work, especially documentation of engineering judgment. By revising "QA Procedure on Design Calculations" and three "Departmental Standards on Design Calculations," S&L has strengthened the requirements for proper documentation of design bases, including assumptions, formulas, steps used in the design, and the appropriate use and documentation of engineering judgment.

On the basis of evaluation of the individual observations and its review of the S&L design process, the IDR team believed that similar use of judgment by qualified, experienced engineers would produce results similar to those found in the IDR for other safety-related systems, structures, and components.

The staff reviewed the S&L documents, "QA Procedure on Design Calculations" and three "Departmental Standards on Design Calculations" and concurs with the modifications. The staff verified that these changes would apply on a companywide basis and that the changed procedures adequately addressed the problems identified. The staff also observed evidence of training of personnel in the new procedures. The staff considers the action taken to be sufficient.

Document Change Control

Documents are changed to reflect design changes and design evolution. Important design documents like design criteria should be updated if design requirements are changed, and relevant design information must then be properly communicated to others affected by the design change. Lack of rigorous control in this activity contributed to the discrepancies in 15 observation reports.

A new project instruction has been issued by S&L to ensure that, when a field design change is made, the affected documents are identified and the incorporation of the change into these documents is monitored. In addition, the effect of the change on the FSAR, the calculations, the Technical Specifications, and any other design documents is identified. This procedure supplements the procedures that are already in place.

A revised design change control procedure in the form of a new project instruction is also being implemented by S&L which provides the requirements for the preparation of design change packages. These packages will be prepared whenever a major design change is identified. The packages will then be reviewed to determine when and how they will be implemented. This procedure provides improved control of design changes.

The staff reviewed the following S&L documents: (1) signoff sheets showing design criteria are being maintained current, (2) signoff sheets showing project personnel training in the new project instructions, (3) procedure for preparing design change packages and by which changes will be incorporated into interfacing documents, and (4) procedures for review of all physical changes against all design bases. The staff in general found these documents acceptable in addressing the problems identified in this area.

FSAR Control

The IDR team identified a number of discrepancies between the FSAR and design documents. In each case, resolution of the discrepancy required a modification of the FSAR rather than a design change. Although S&L could have implemented tighter FSAR control, the IDR team does not believe that this group of observations indicates an adverse trend which could result in a serious deficiency. That is, other discrepancies between the FSAR and design documents would be resolved in a manner similar to those found in the IDR.

The staff reviewed the results of the FSAR certification program. This program, which had been initiated by the applicant before the IDR, consists of a line-by-line review of the FSAR to verify that commitments were being incorporated in the appropriate design documents. The staff observed substantial evidence that the program was well under way, along with evidence that the personnel

involved were trained in the details of the program. The staff feels that this is an effective ongoing program which would have uncovered many, if not all, FSAR control problems revealed by the IDR.

Design Communications

The IDR team found that, in some cases, there was doubt that the design intent would always be properly communicated to affected design groups. For the most part, some of the various discipline design procedures required changes to remove ambiguities or inconsistencies which, if uncorrected, could add confusion to the design process.

Overall, where this situation seems to have been the cause of an observation, close examination of the context of each item by the IDR team revealed that the overall design process was functioning properly and that the specific design condition was adequate and in conformance with the design criteria and licensing commitments. The IDR team did not consider this group to constitute a trend which is likely to have adverse effects on the adequacy of the systems and structures not reviewed.

S&L has taken actions to enhance the design communication process in specific areas through the additional documentation requirements detailed in the responses to individual observations.

In addition, S&L has issued a new procedure on design information transmittal which formalizes the transmittal of design information between project team members in the various disciplines. This procedure covers the transmittal of design input which is not already addressed in existing standards or procedures. It requires documentation of the basis for design information, including identification of preliminary design inputs.

The staff reviewed this procedure on design information transmittals (DITs) and considers it acceptable to resolve this concern.

Vendor Document Review

In six cases, the IDR team found that vendor document review was not complete or accurate. This condition appeared to be a generic problem from the number of instances identified. Accordingly, S&L has committed to a comprehensive review of equipment qualification documentation. In each case, however, additional qualification data were provided by the vendor or developed by S&L to support the qualification of the equipment.

In the March 21, 1985, letter, the applicant indicated that, of the six instances of incomplete vendor review identified by the IDR, several were in packages not yet reviewed by the Seismic Qualification Review Team (SQRT) audit using revised checklists. Nevertheless, the applicant committed to taking further steps to upgrade vendor document review. This commitment involved further reviews of vendor packages and training of personnel. The staff observed evidence of both the further review and training in this area. The staff finds the applicant's response and action to date to be sufficient. Implementation of the equipment qualification program will be the subject of NRC inspections during plant operations.

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Code Compliance

With regard to Code compliance issues, these items largely involved questions of Code interpretation. The IDR team concluded that the design was adequate in each instance of possible Code violation and that the conditions were random in nature. The applicant concluded that there was no trend identified at Clinton and no corrective action was necessary. The staff concurs with the applicant's conclusion for the following reasons:

(1) There were six issues raised of the hundreds, and perhaps thousands, of Code applications.

(2) One of the six had a previous Code case initiated.

(3) Of the remaining five items, the design was found adequate in each instance.

17.5.5 NRC Staff Conclusions

The applicant contracted with Bechtel Power Corporation to undertake an independent design review of the design activities of Clinton Unit 1. The review involved a substantial effort which evaluated more than 2900 documents and expended approximately 31,000 man-hours. The NRC staff closely monitored the review at all stages of its activities, including subsequent corrective actions. In view of monitoring performed by the staff (as detailed in this supplement), the staff concludes that the IDR provides additional confidence that the design of Clinton is in accordance with design requirements and published regulations. In addition, the staff concurs with the IDR conclusion that further review work would, in all likelihood, produce results similar to the IDR. Further independent design review of Clinton Unit 1, other than that indicated in this supplement, is not considered warranted.

22 REPORT OF THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

In Supplement No. 1 to the SER, the staff identified three issues contained in the Advisory Committee on Reactor Safeguards (ACRS) report to the Chairman of the Nuclear Regulatory Commission, dated March 9, 1982 (Appendix E to SSER 1), that would be reviewed by the staff and reported on in a future supplement to the SER. These are: (1) staffing for plant startup and operation; (2) the applicant's revised quality assurance program; and (3) the applicant's seismic assessment program that addresses the ACRS's concern related to the seismic capability of the emergency ac power supplies, the dc power supplies, and the small components such as actuators and instrument lines that are part of the decay heat decay removal system:

(1) Staffing for Plant Startup and Operation

Staffing for plant startup and operation was addressed in Section 13 of Supplement 5 to the SER (SSER 5) and is also addressed in Section 13 of this supplement. The staff has concluded that the staffing of Clinton, with the additional commitments made by the applicant based on the staff's evaluation, satisfies the regulatory requirements and is, therefore, acceptable.

(2) Quality Assurance Report

In the March 9, 1982, letter from P. Shewmon, Chairman of the ACRS, to NRC Chairman N. Palladino (Appendix E, SSER 1), the ACRS asked to be informed of the applicant's restructuring of the construction and operations quality assurance (QA) and quality control (QC) organization. The Region III staff has written a quality assurance report, contained in Appendix M, which discusses some of the actions taken by the applicant to correct those problems. This report also describes subsequent NRC inspection activities at Clinton, including staff findings of quality assurance and construction deficiencies and the actions taken by the applicant to correct them. The report concludes that the applicant's quality assurance program for construction and preoperational testing at Clinton is acceptable.

(3) Safety Evaluation of the Clinton Equipment Seismic Assessment Program

In a letter from F. A. Spangenberg to W. Butler dated October 14, 1985, the applicant submitted to the staff a report entitled, "Clinton Power Station Equipment Seismic Assessment Program for Safety-Related Mechanical and Electrical Equipment." The report provides the results of the Equipment Seismic Assessment Program (ESAP) initially proposed in a letter from G. E. Wuller to J. R. Miller dated May 19, 1982. The program was developed in response to a concern expressed by the ACRS in a letter from P. Shewmon to N. Palladino dated March 9, 1982, which stated that "specific attention be given to the seismic capability of the emergency AC power supplies, the DC power supplies, and small components such as actuators and instrument lines that are part of the decay heat removal system."

The implementation of the Equipment Seismic Assessment Program was divided into three phases by the applicant. Phase I examined the seismic design adequacy

of small-bore piping and instrumentation lines. Phase II involved a plant walk-down of the decay heat removal and emergency power supply systems to identify potential seismic interactions. Phase III evaluated the ability of equipment in these systems to withstand an earthquake based on revised seismic response spectra developed using an elastic half-space approach for soil-structure interaction.

The staff has completed its review of the Clinton Power Station Equipment Seismic Assessment Program (ESAP) and finds the concern expressed by the ACRS has been addressed in a manner satisfactory to the NRC staff. The details of the staff's review of the three phases are provided below.

Phase I - Small-Bore Piping Design

Applicant's ESAP Approach

The Phase I scope for the review of the small-bore piping design included the small-bore piping (2 inches and less nominal pipe size) and instrumentation lines designed by Sargent & Lundy (S&L), the architect-engineer (AE). Small-bore lines supplied with equipment by the vendors were reviewed as part of Phases II and III of the ESAP. The Phase I approach for the design review consisted of two parts. First, all safety-related small-bore piping associated with the decay heat removal and emergency power systems were reviewed to ensure that a design calculation had been performed for each small-bore piping subsystem. Second, the applicant reviewed the adequacy of the small-bore piping design guidelines and the adequacy of their application in the design calculations.

In the applicant's review to assess the completeness of the small-bore piping calculations, all safety-related small-bore piping was identified in the residual heat removal, shutdown service water, diesel generator, and diesel fuel oil systems. The applicant reviewed the piping line lists and the piping and instrumentation diagrams (P&IDs) to ensure that the list of safety-related small-bore piping associated with these four systems was complete. The applicant then conducted a review to verify that each safety-related piping system identified had a design calculation or other qualification method associated with it. One of three approaches was found to be used for the design of small-bore piping. The three approaches were as follows:

(a) Small Piping Procedure - S&L Procedure EMD-015666, "The Small Piping Procedure for Restraint of Seismically Qualified Small Piping," provides a simplified methodology for qualifying small-bore piping and pipe supports.

(b) PIPSYS Analysis - A computer program (PIPSYS) provides a detailed method using finite element analysis techniques to calculate piping stresses and support loads.

(c) Small Tap Line Design Guidelines - A standardized drawing detail provides a qualified method to design vents, drains, and instrument taps connected to large pipe headers for seismic and flow-induced vibration loadings.

In the applicant's review of the adequacy of the design methods and calculations, the small piping procedure and the design calculations were reviewed to determine the quality of the procedure's application. A technical review of the small-bore piping design calculations found several discrepancies in the selected sample. As a result, in a letter from D. P. Hall to J. G. Keppler dated October 1, 1982 (Potential Deficiency 82-09), the applicant reported this condition to the NRC staff as a potentially reportable deficiency in accordance with 10 CFR 50.55(e).

Subsequently, the discrepancies in the small-bore piping design calculations were corrected and the small piping procedure was revised to prevent the recurrence of discrepancies. Additionally, as a result of a generic implication evaluation, the AE initiated a program of technical reviews and quality assurance audits in other areas of the Clinton design that used procedures similar to the small-bore piping procedure. These areas included HVAC supports, cable tray supports, large-bore pipe support auxiliary steel, reinforcement of branch connections in piping, welded attachments to piping, pipe rupture restraints, and expansion anchors. Corrective measures were established and implemented and safety significance was evaluated. Although hardware modifications were required to bring the affected piping into compliance with the ASME Boiler and Pressure Vessel Code, the evaluation by the AE determined that the errors, if left uncorrected, would not have impacted the ability to safely shut down the plant and maintain it in a safe shutdown condition. Thus, in a letter from D. P. Hall to J. G. Keppler dated June 15, 1984, the applicant reported to the staff that the issue did not represent a reportable deficiency under 10 CFR 50.55(e), and the issue was closed.

Staff Review and Evaluation

The staff reviewed the submittal of the ESAP provided in the October 14, 1985, letter. In addition, on January 16, 1986, the staff performed an audit at the Clinton facility of the ESAP Phase I program results. The staff reviewed the small piping procedure (EMD-015666, Revision 4, dated July 17, 1985), selected design calculations, and related project instructions. The staff also discussed the specific types of errors which were identified in the piping design review, the corrective measures which were made to the procedure to preclude the recurrence of the errors, and the conclusions drawn regarding the root cause and generic implications of the deficiencies. Additionally, the staff reviewed the design of small tap lines and their qualification method. On the basis of its review, the staff concludes that the focused review performed under ESAP by the applicant provides added assurance that the safety-related small-bore piping associated with the decay heat removal and emergency power supply systems can withstand the effects of a safe shutdown earthquake and perform their safety functions. The actions taken by the applicant following its identification of the potential design deficiencies demonstrated the applicant's ability to adequately evaluate their safety impact including root cause and generic implications and to implement corrective measures.

Phase II - Interaction Analysis

Applicant's ESAP Approach

The ESAP Phase II interaction analysis primarily consisted of a supplemental plant walkdown of selected safety-related equipment and piping in the residual

heat removal, shutdown service water, diesel generator, and diesel fuel oil systems to identify potential seismic interactions and interferences.

The ESAP walkdowns were performed by Illinois Power's Nuclear Station Engineering Department (NSED). The NSED walkdown teams reviewed the installed systems for the following types of problems during the walkdowns:

- potential seismic interactions of piping, valves, conduit, cable trays, hangers, and other equipment
- unusual or inadequate supporting of piping, valves, and conduits that have the potential to be damaged from seismic loadings
- equipment that might be susceptible to damage resulting from seismic loads
- certain non-seismic problems which could be caused by interferences, or by damaged or improperly assembled equipment

The NSED walkdowns reviewed 22 plant areas related to the decay heat removal and emergency power supply systems. Potential interactions identified during the walkdowns were documented and evaluated to determine their significance and the corrective action, if any was taken, to resolve the concerns. The results of the NSED walkdowns and the actions taken are documented in Appendix A of the applicant's ESAP report.

Staff Review and Evaluation

The staff reviewed the Clinton ESAP report including the results provided in Appendix A of the report. In addition, on January 16, 1986, the staff performed a site walkdown audit of several areas reviewed by the NSED team. The staff reviewed NSED walkdown areas 2, 3, and 15 as described in Appendix A of the ESAP report. Area 2 is the RHR loop A pump room (auxiliary building, elevation 707 feet). Area 3 is the RHR loop A heat exchanger room (auxiliary building, elevations 707, 737, 762, and 782 feet). Area 15 is the Division III diesel generator room (diesel generator building, elevation 737 feet).

In conjunction with its walkdown audit, the staff verified that the seismic interactions and interferences had been properly resolved. The staff noted that many of the proposed actions provided in the ESAP report to correct the identified problems had been implemented in the plant. The staff found that the actions taken by the applicant to resolve the potential seismic interactions and interferences were adequate.

The staff noted in the ESAP report that the diesel generators were not examined by the NSED team during the walkdowns because of the equipment qualification program being conducted for the diesel generators. The staff raised a question regarding the method used to qualify the small-bore lines supplied with the diesel generators. Because the May 19, 1982, proposed program stated that the purpose, in part, of the field inspection was to "review major component configurations to assure that small lines supplied with the equipment are adequately supported," and because the diesel generators contained many vendor-supplied small-bore lines, the staff focused its review on the qualification of these lines. Furthermore, the staff performed a walkdown of the Division III diesel generator to review the seismic adequacy of the vendor-supplied small-bore lines.

The staff noted in its field walkdown audit that the small-bore lines attached to the diesel generator appeared to be seismically well supported. In addition, the Division III diesel generator was in operation at the time of the audit and there was no evidence of excessive operational vibration in the attached small-bore lines.

The staff also discussed the method used for the seismic qualification of the small-bore lines attached to the diesel generators. The staff found that as a part of the equipment qualification program, the diesel generator vendor (Stewart and Stevenson) contracted with Southwest Research Inc. (SWRI) to identify all components on the diesel generator (including the small-bore lines). SWRI reviewed the schematic drawings and walked down each engine to verify the completeness of the drawings. All the components (including small-bore lines) were identified and listed in a computerized log. In addition, the organization responsible for the seismic qualification of each diesel generator component was listed in the log. Specifically, the small-bore piping supplied with the diesel generator was qualified by S&L using S&L's PIPSYS computer program. The large-bore piping (6- and 8-inch) was analyzed by SWRI using SWRI's finite-element computer program. The staff found the seismic qualification of the vendor-supplied small-bore piping to the diesel generators to be adequately addressed and acceptable.

On the basis of its review of the ESAP report and its audit performed on January 16, 1986, the staff concludes that the seismic interaction walkdown performed in conjunction with the ESAP provides further assurance that the piping and equipment associated with the decay heat removal and emergency power supply systems can withstand the dynamic effects of a safe shutdown earthquake at the Clinton site.

Phase III - Equipment Evaluation

Applicant's ESAP Approach

Phase III consisted of evaluating equipment stress levels for loadings on the basis of the revised response spectra. The revised spectra were developed using the elastic half-space approach for soil-structure interaction analysis which is different from the finite-element approach that was used in developing the design-basis qualification spectra. The purpose of the evaluations was to demonstrate the ability of selected equipment important to decay heat removal and emergency power supply to survive an earthquake of the type described by the revised response spectra. Two types of stress evaluation were utilized for Phase III. For equipment that was seismically qualified by test, the test response spectra were shown to envelope the revised response spectra in the frequency range of interest for the equipment. For equipment that was being seismically qualified by analysis, the acceleration values used in the analysis were shown to exceed the corresponding acceleration values from the revised response spectra, or the component's critical stresses were calculated and shown to be within applicable Code-allowable limits.

Staff Review and Evaluation

On the basis of the information provided by the applicant in its October 14, 1985, letter, the staff found that there was sufficient assurance that the emergency power supply and decay heat removal systems can withstand the safe shutdown

earthquake, with the following exception: The qualification test reports for the Division III diesel generator and its accessories were, at the time, still being reviewed for acceptability by the applicant and its consultant, Sargent & Lundy Engineers.

By letter dated March 3, 1986, the applicant confirmed that it has completed the seismic qualification reevaluation of the remaining equipment items. The reevaluation indicates, and the staff concurs, that the Division III diesel is capable of withstanding an earthquake of the form predicted by the revised response spectra.

The staff's review of the applicant's overall seismic qualification program is continuing. However, in view of the nature of the remaining open items to be resolved by the applicant, which consist primarily of concerns regarding qualification of active valves and of some equipment-specific concerns not related to the subject ESAP, the results of that review will not affect the staff's conclusion regarding the applicant's ESAP.

APPENDIX A

CONTINUATION OF CHRONOLOGY

December 11, 1985	Letter from applicant forwarding construction status report (NUREG-0030) for period ending September 30, 1985. Construction is 97.1% complete. Sixty-one-day delay to fuel load is due to preparation of preoperational test procedure for fire protection system per October analysis.
December 17, 1985	Summary issued of December 20, 1985, meeting with Hydrogen Control Owners Group about status and results of hydrogen combustion tests in quarter-scale test facility (Mark III).
December 18, 1985	Letter from applicant forwarding response to unresolved items identified by Seismic Qualification Review Team's (SQRT's) August 27-30, 1985, inspection concerning SER outstanding issue 7ii, "Seismic and Dynamic Qualification of Equipment." Responses to SQRT open items NSSS 3.1, BOP 2.1, and BOP 2.2 are also enclosed.
December 20, 1985	Letter from applicant modifying November 19, 1984, description of automatic depressurization system (ADS) accumulator low-pressure alarm. Common annunciator will indicate low-pressure condition in ADS accumulators, but accumulator cannot be identified at plant computer.
December 23, 1985	Letter from applicant forwarding Revision 1 to "Offsite Dose Calculation Manual," incorporating NRC comments of August 26, 1985, about meteorological model, recent meteorological data supplied by Sargent & Lundy, and describing methods used by Nuclear Data System.
December 24, 1985	Summary issued of December 16, 1985, meeting with utility in Bethesda, Maryland, about accelerated power ascension program.
December 24, 1985	Letter to applicant informing applicant that Revision 6 to physical security plan, Revision 5 to guard qualification and training plan, and Revision 3 to security contingency plan continue to meet regulatory requirements.
December 26, 1985	Letter from applicant requesting exemption from NUREG-0737, Item II.F.1, requirement about in situ calibration of drywell high-range radiation monitors.

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December 26, 1985	Letter from applicant forwarding "Clinton Power Station Inservice Inspection Pump and Valve Testing Program," per SER (NUREG-0853) confirmatory issue 68. Program describes how requirements of ASME Boiler and Pressure Vessel Code, Section XI, will be met.
December 31, 1985	Letter from applicant forwarding responses to open items NSSS 1.1, 1.2, and 1.3 and Generic Item 5 identified during Seismic Qualification Review Team visit of August 27-30, 1985, about SER outstanding issue 7ii.
January 3, 1986	Generic Letter 86-01 issued to all boiling-water reactor (BWR) applicants and licensees about safety concerns associated with pipe breaks in BWR scram system.
January 7, 1986	Letter from applicant forwarding response to October 29, 1985, request for additional information about initial plant test program.
January 7, 1986	Letter to applicant discussing review of February 9, 1985, request for Standard Review Plan (SRP) deviation from postulating pipe break in residual heat removal (RHR) heat exchanger (HX) cubicles. Request for deviation was granted. Amendment to FSAR Section 3.6.2 was requested.
January 8, 1986	Letter from applicant informing staff that instrument tubing hanger supports were independently inspected as part of overinspection program. No significant safety problems were identified. Overinspection program for hangers was terminated with Region III concurrence.
January 8, 1986	Letter from applicant discussing utility resolution of commitment for qualification of Supervisor of Chemistry in FSAR, Page 1.8-16b, Item 4.
January 8, 1986	Letter from applicant forwarding Federal Emergency Management Agency (FEMA) memorandum of December 13, 1985, enclosing interim finding on offsite radiological emergency preparedness plans.
January 9, 1986	Letter to applicant accepting instrument tubing and supports program described in submittals of July 18, August 23, and November 18, 1985, and January 8, 1986. FSAR should be revised accordingly.
January 10, 1985	Letter from applicant discussing status of design, construction, and preoperational testing of facility per FSAR in support of fuel load. Fuel loading will occur between late February and early March 1986.
January 10, 1986	Letter to applicant forwarding Federal Register (FR) notice about request for reevaluation finding affirming updated no-significant-antitrust change. Director will not amend updated no-significant-change finding.

January 16, 1986	Letter from applicant responding to concern about methodology on reverse vent flow modeling identified in NRC review of utility's November 14, 1985, letter. Comparison of Sargent & Lundy and GE methodology is enclosed. Information closes out SER outstanding issue 9.
January 16, 1986	Letter from applicant responding to SER outstanding issue 7ii and unresolved items identified by SQRT during August 27-30, 1985, visit. Responses to SQRT open item NSSS 10.1 and generic item 8 are also enclosed.
January 17, 1986	Letter from applicant forwarding Revision 7 to physical security plan, updating and clarifying existing information.
January 17, 1986	Summary issued of December 18, 1985, meeting with Mark III Containment Hydrogen Control Owners Group about combustible gas control emergency procedure guideline.
January 17, 1986	Summary issued of December 18, 1985, meeting with Mark III Containment Hydrogen Control Owners Group about heat sink modeling.
January 17, 1986	Summary issued of January 13, 1986, meeting with utility and Region III personnel in Bethesda, Maryland, about fuel load readiness and definition of approach for completing remaining tasks.
January 22, 1986	Letter from applicant forwarding description of current and proposed fire protection program. Fire protection evaluation report and safe shutdown analysis will be incorporated into FSAR Chapter 9, and Technical Specifications sections will be deleted before fuel load.
January 22, 1986	Letter to applicant forwarding for comments by February 24, 1986, two draft reports about probabilistic risk assessments (PRAs). Insights about plant strengths and weaknesses, core melt frequency, procedural and hardware modifications, and PRA methodologies are discussed.
January 23, 1986	Generic Letter 86-02 issued to all licensees of operating BWRs about technical resolution of Generic Issue B-19, "Thermal-Hydraulic Stability."
January 23, 1986	Letter to applicant forwarding SSER 5 (NUREG-0853) about application for operating license (OL) for facility.
January 24, 1986	Letter from applicant forwarding calculations providing design basis for FSAR discussion on electrical separation, including Revision 0 to 19-BD-2, 19-BD-8, 19-BD-11, 19-BD-12, 19-BD-13, 19-BD-15, 19-BD-16, and 19-BD-17, and Revision 1 to 19-BD-5, 19-BD-7, and 19BD-10.

January 27, 1986	Letter from applicant forwarding justification for not installing heat tracing to high-range effluent monitor sample lines per NUREG-0737, Item II.F.1, "Additional Accident Monitoring Instrumentation," and staff request of November 6, 1986.
January 27, 1986	Letter from applicant forwarding Amendment 36 to Clinton Power Station FSAR.
January 27, 1986	Letter to applicant forwarding request for additional information about November 5, 1985, response to open item identified during August 1985 site audit. Information on seismic issue should be identified at January 28, 1986, meeting.
January 28, 1986	Letter from applicant advising staff that mobile radwaste solidification system will be operated, per Associated Technologies, Inc., ATI-VR-001-P-A. Compliance with 10 CFR 61 regarding disposal of radwaste is addressed in Supplement 2 to report.
January 29, 1986	Letter from applicant forwarding percent complete profile, utility's nuclear power program key events, and system turnover tracking charts through November 1985, per July 1984 site visit.
January 31, 1986	Letter from applicant informing staff of completion of July 15, 1985, committed actions regarding SER confirmatory issue 69 concerning containment vent and purge valve operability, including installation of mechanical stops to limit opening angles for valves.
January 31, 1986	Letter from applicant discussing distribution of emergency information brochure informing reader of initial action to take in event of a major emergency.
January 31, 1986	Letter from applicant reporting completion of commitments made regarding Generic Letter 82-33 Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability." Hydrogen control emergency operating procedure to be implemented before exceeding 5% of rated power.
January 31, 1986	Letter from applicant forwarding list of seismic and dynamic qualification of equipment, in response to SER outstanding issue 7ii identified by SQRT during August 27-30, 1985, visit.
February 4, 1986	Letter from applicant providing update on construction schedule, per May 29, 1981, request. New organization has been formed to coordinate fuel load readiness. Integrated leak rate test has been successfully completed. Emergency core cooling system (ECCS) loss of offsite power testing is incomplete.

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February 5, 1986	Letter from applicant confirming that corrective action has been completed for observation reports 1, 10, 29, 34, 55, 57, 64, and 74. Gaps between batteries and battery rack-end rails are eliminated by installing spacers between end cells and battery rack-end rails.
February 5, 1986	Letter from applicant advising staff that postulated high-energy pipe breaks inside drywell are reviewed for jet impingement effects on grating. Two postulated breaks will produce direct jet forces perpendicular to grating. Grating will not be displaced.
February 5, 1986	Letter from applicant submitting detailed justifications concerning power ascension program acceleration test modifications. Expedited review of test modifications is requested since modifications impact resolution of detailed procedures.
February 10, 1986	Generic Letter 86-03 issued to all licensees of operating reactors and applicants for OL concerning applications for license amendments.
February 12, 1986	Letter to applicant forwarding notice of environmental assessment and finding of no significant impact regarding exemptions from certain 10 CFR 50 requirements concerning airlock testing.
February 13, 1986	Letter from applicant reviewing Ruskin fire damper installations. Sargent & Lundy analysis determined that additional welded corner closure angles do not hinder damper ability to close during 3-hour ASTM E-119 fire condition.
February 13, 1986	Letter from applicant requesting deletion of Technical Specifications regarding non-safety loads on emergency sources and redundant fault protection for power generation control complex (PGCC) fire protection, communication, reactor protection system, and main steam isolation valve (MSIV) circuits, per SER (NUREG-0853).
February 13, 1986	Generic Letter 86-04 issued to all power reactor licensees and applicants for power reactor licenses concerning policy statement on engineering expertise on shift.
February 14, 1986	Letter from applicant responding to SSER 5, SER outstanding issue 7ii concerning seismic and dynamic qualification of equipment. Responses to Section 3.11.5, Items 1-3, and related documentation are enclosed.
February 14, 1986	Letter to applicant forwarding comments on Revision 1 to "Offsite Dose Calculation Manual." Manual uses methods consistent with NUREG-0133 methodology and guidelines, and is acceptable.

February 17, 1986	Letter from applicant requesting deviation from 325°F maximum temperature criterion on unexposed side for penetration seal qualification fire tests. Supporting information is listed. Temperature of conduit seals does not decrease level of fire protection in plant.
February 17, 1986	Letter from applicant submitting current status of design, construction, and preoperational phase testing. Progress continues to support goal for fuel load during first quarter of 1986. Activities needed to support fuel load and preparations for testing are listed.
February 21, 1986	Letter from applicant responding to November 6, 1985, request for information about preliminary analysis of plant hydrogen control system. Equipment survivability to be demonstrated by conducting analysis of igniter assembly. Additional analysis is unwarranted.
February 25, 1986	Letter from applicant informing staff that Regulatory Guide 1.97 instrument sensors and control room indicators have been installed per December 11, 1984, commitment. Equipment upgrading for reactor vessel fuel zone water level instruments will be completed before restart.
February 27, 1986	Letter from applicant forwarding response to SER outstanding issue 7ii concerning seismic and dynamic qualification of equipment, per SSER 5 (NUREG-0853). Responses to Table 3.1 open items BOP-6 and NSSS 3.2, 9.1, and 9.2 are also enclosed for review.
March 3, 1986	Letter from applicant confirming that seismic evaluations completed for Division III diesel generators, per January 23, 1986, telephone conversation request. Capability for withstanding earthquake in form predicted by revised response spectra is verified.
March 4, 1986	Letter from applicant forwarding Amendment 1 to fire protection evaluation report and safe shutdown analysis. Amendment 1 presents changes that update and clarify information.
March 7, 1986	Letter from applicant forwarding response to October 18, 1985, letter regarding fire protection site audit concern. Design clarification is provided for unprotected structural steel forming part of fire barrier in diesel generator day tank room.
March 7, 1986	Letter from applicant responding to unresolved item about pump and valve operability qualification identified by Pump and Valve Operability Review Team during January 28-29, 1986, technical session. Vendor has selected 100 impact tests to meet Specification K-2873A requirements.

March 10, 1986	Letter from applicant forwarding proposed calibration methodologies for effluent radiation monitors. Accident range effluent radiation monitors are installed to meet requirements of NUREG-0737, Item II.F.1.
March 10, 1986	Letter from applicant forwarding Revision 3 to Calculation 19-BDA-1, "Calculation for Establishing Required Raceway/ Cable Separation Distances." Calculation provides portion of design basis for FSAR discussion on electrical separation.
March 10, 1986	Letter from applicant providing information to resolve SSER 6 outstanding issue 13 on remote shutdown system. Requests deferral of Technical Specification implementation for Division II components until startup from first refueling outage per SRP (NUREG-0800).
March 11, 1986	Letter from applicant forwarding justification for December 9, 1985, request for exemptions from 10 CFR 50.12, Appendix J, final rule concerning leak test requirements, specifically, MSIV leak rate tests and containment air lock leakage testing.
March 11, 1986	Summary of January 28-29, 1986, meetings with utility, Sargent & Lundy, and Brookhaven National Laboratory (BNL) in Chicago, Illinois, about test vs. analysis concern for active valve qualification identified during SQRT and PVORT audits.
March 12, 1986	Letter from applicant notifying staff of revision to FSAR Section 5.4.8.1, Figure 5.4-17, reflecting administrative control of reactor water cleanup (RWCU) system to ensure feedwater piping temperature of 435°F or less, consistent with recent analyses.
March 12, 1986	Letter from applicant forwarding responses to four of five open generic items and specific concerns about Component 1-E22-F010, per NRC Pump and Valve Operability Review Team January 28, 1986, draft SER.
March 12, 1986	Letter from applicant requesting deferral of listed preoperational test items until after fuel load. Construction activities to support fuel load will be completed. Technical justification and measures for controlling deferred activities are enclosed.
March 17, 1986	Letter from applicant responding to findings noted during October 29-30, 1985, onsite inspection of electrical circuits and drawing review. Procedures are in place to ensure that reactor protection system's uninterruptible power supply devices retain Class 1E qualification.

March 17, 1986	Letter from applicant forwarding additional preservice inspection program relief request about visual examination of component supports per SSER 1 and 2. Program will employ Class 3 selection criteria in ASME Code Section XI, Winter 1980 Addenda.
March 17, 1986	Letter from applicant forwarding Revision 0 to Calculation 19-BD-25 concerning splices in Class 1E cables in conduit, per NRC request.
March 17, 1986	Letter from applicant forwarding explanation of how safe shutdown analysis path methodology is determined at facility, in response to February 27, 1986, request concerning 10 CFR 50, Appendix R, compliance.
March 18, 1986	Letter from applicant forwarding Revision 1 to facility inservice testing program for pumps and valves.
March 18, 1986	Letter to applicant forwarding request for additional information on SER outstanding issue I5 on common electrical power source or sensor malfunctions or individual high-energy-line breaks.
March 19, 1986	Letter from applicant forwarding proprietary Bisco Reports 748-15, "Conduit Seal Fire Barrier Testing," and 748-66, "Fire Testing Utilizing Bisco SF-20 in Both 6" O Steel Conduit and 6" O PVC Duct Configurations."
March 20, 1986	Generic Letter 86-07 issued to all reactor licensees and applicants regarding transmittal of NUREG-1190 concerning San Onofre Unit 1 loss of power and water hammer event.
March 20, 1986	Letter from applicant notifying staff that W. P. Mullins has been appointed Chemistry Supervisor to strengthen management within Chemistry Department.
March 27, 1986	Letter from applicant responding to IE Information Notice 85-09 regarding potential deficiencies in electrical design of isolation transfer switches installed outside control room. Concern is inapplicable to facility.
March 27, 1986	Letter from applicant forwarding revised comments on General Electric Co. (GE) evaluation of electrical and functional independence of electrical protection assembly and inverter circuits, per telephone conversation of February 25, 1986, and onsite inspection (October 29-30, 1985) of electrical circuits and drawing review.
March 27, 1986	Letter from applicant informing staff that motor-operated valve analysis test system will be completed for safety-related motor-operated valves before exceeding 5% of rated power, per NRC request.

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March 27, 1986	Letter from applicant requesting specific exemptions to General Design Criteria of 10 CFR 50, Appendix A, for deferral of preoperational testing only.
March 31, 1986	Letter from applicant clarifying method used to ensure facility could be safely shut down after postulated moderate-energy-line break in areas outside containment. Safe shutdown will be achieved through use of separated redundant equipment.
March 31, 1986	Letter from applicant forwarding qualification installation status by equipment number report for February 1986, in response to open item 5, Section 3.10.1.3 of SSER 5 (NUREG-0853).
March 31, 1986	Letter from applicant regarding FSAR Amendment 37.
April 2, 1986	Letter from applicant responding to question about sufficient personnel to safely shut down plant in event of fire. Fire brigade is composed of one senior reactor operator, two other operators, a radwaste operator, and a radiation protection technician.
April 4, 1986	Letter from applicant clarifying acceptability of cable routing per NRC request. Equipment associated with two Division 2 instrument cables consists of Method 1 safe shutdown components. Failure of cables will make Method 1 safe shutdown unavailable.
April 14, 1986	Letter from applicant forwarding Sargent & Lundy Calculation COD-027437, Revision 0, verifying that welded corner closure angles of Ruskin fire dampers do not hinder damper performance, per NRC request. Design features were discussed during telephone conversation of April 2, 1986.
April 15, 1986	Letter from applicant advising staff that pump and valve qualification packages for all identified active pumps and valves have been completed by Sargent & Lundy Engineers. Pump and valve operability review team documentation is maintained in auditable form.
April 16, 1986	Letter from applicant submitting current status of plant design, construction, and preoperational phase testing. Utility is in final process of testing plant in preparation for fuel load. Fuel load is anticipated in late June or early July 1986.
April 16, 1986	Letter from applicant forwarding addendum information about power ascension program Acceleration Test Package STP 8.0, "Control Rod Sequence Exchange Test Deletion." Information provides examples of startup test programs using GE procedures.

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April 17, 1986	Letter from applicant responding to March 18, 1986, request for additional information about control system failure (outstanding licensing issue 15). "TOP-DOWN" approach is used to resolve issue. Additional analysis will be completed before operation above 5% of rated power.
April 18, 1986	Letter from applicant forwarding utility's current and near-term plans for shift technical advisor program in response to Generic Letter 86-04.
April 18, 1986	Letter from applicant responding to unresolved PVORT items on pump and valve operability qualification discussed during February 20 and 21, 1986, telephone conversations. No valve assembly failures similar to 1-E22-F010 and 1-E22-F011 were noted during February 1986.
April 18, 1986	Letter from applicant forwarding responses to SER Outstanding Issue 7ii concerning seismic and dynamic qualification of equipment discussed in SSER (NUREG-0853). Proprietary enclosures are withheld.
April 21, 1986	Letter from applicant providing additional commitments about Division II remote shutdown testing to resolve SER Outstanding Issue 13 as required by NRC. Revisions to Procedure 4003.01 are being implemented to ensure proper circuit alignments during jumping and rewiring of equipment.
April 23, 1986	Letter to applicant forwarding list of proposed changes to approved power ascension test program proposed in applicant's letter of February 5, 1986. Two startup test exceptions are listed. FSAR should be amended to reflect approved changes.
April 24, 1986	Generic Letter 86-10 issued to all power reactor licensees and applicants for power reactor licenses about implementation of fire protection requirements.
April 29, 1986	Letter from applicant submitting quarterly update of construction schedule, per staff's May 29, 1981, request. Completion of testing and preparation of systems for operation is priority. Fuel load date will be later than expected, as determined by NRC.
April 30, 1986	Letter from applicant forwarding response to SSER 5 (NUREG-0853), Section 3.10.1.3, Outstanding Item 9, regarding seismic and dynamic qualification of equipment. Safety-related equipment is qualified.
May 2, 1986	Letter from applicant requesting elimination of ultimate heat sink (UHS) temperature monitoring requirements from Technical Specification 3/4.7.1.2. Monitoring of temperature in area of UHS is unnecessary. UHS temperature analysis weather data for July 24, 1964, is enclosed.

May 5, 1986	Letter from applicant forwarding revised "Post-Accident Sampling System Evaluation Report," to close out requirements of SER License Condition 6, "Post-Accident Sampling" and TMI Action Plan Item II.B.3.
May 6, 1986	Letter from applicant informing staff that acceptance testing of plant process computer historical recording services will not be performed. Historical recording and recall subsystem test deferral request is withdrawn.
May 9, 1986	Letter from applicant discussing plant manager training requirements noted in FSAR Figure 13.2-1. Figure will be revised to require manager to complete damage mitigation class before plant exceeds 5% of rated power.
May 13, 1986	Issuance of Summary of Operating Reactors Events Meeting 86-16 on May 12, 1986, regarding events occurring since the last meeting.
May 14, 1986	Letter from applicant forwarding Prairie Alliance request for utility to discontinue all mailings to organization concerning facility. NRC should contact J. Foy of Prairie Alliance about similar request.
May 15, 1986	Letter from applicant supplementing April 17, 1986, response to NRC's March 18, 1986, request for additional information about SER Outstanding Licensing Issue 15 concerning control failure analysis.
May 19, 1986	Letter from applicant summarizing discussion with NRC concluding that repeat manual testing of portions of nuclear safety protection systems independent of self-test systems surveillance test functions per Technical Specification 1.39 is unnecessary. Marked-up Technical Specifications are enclosed.
May 23, 1986	Letter from applicant submitting additional information to support October 16, 1985, commitment to comply with 10 CFR 50.62(c)(4) regarding anticipated transient without scram requirements for equivalent control capacity, per Generic Letter 85-03. Figure 3.1.5.-1, regarding revised minimum sodium pentaborate solution concentration is enclosed.
May 27, 1986	Letter from applicant providing justification for revising Technical Specifications Table 4.3.3.1-1. Revision involves deleting requirement for high-pressure core spray system during reactor startup due to reactor wide-range water level instrumentation not being calibrated for startup conditions.

May 29, 1986	Letter from applicant requesting additional exemptions to general design criteria of 10 CFR 50, Appendix A, based on results of deferral request contained in "Initial Test Program Activities Projected for Completion After Fuel Load." Justification is enclosed.
May 29, 1986	Letter from applicant documenting justification that fire in vicinity of valves listed in Section 3.5.1.2, Paragraph 2, of safe shutdown analysis will not prevent plant shutdown.
May 30, 1986	Letter from applicant forwarding information about safety/relief valve discharge line sleeve annulus condensation oscillation load and conservatism in spatial attenuation per request for additional information on SER (NUREG-0854) Confirmatory Issue 71 - Humphrey Concerns.
June 2, 1986	Letter from applicant providing current status of design, construction, and preoperational phase testing of facility, describing status as revised from letter of April 16, 1986, on readiness to load fuel. Progress continues to support July 1986 fuel load.
June 6, 1986	Letter from applicant forwarding Revision 2 to Nuclear Station Engineering Instruction NSEI CS-4, "UHS Monitoring," to be used to implement Technical Specifications administration program for monitoring and maintenance of UHS, per staff request.
June 9, 1986	Memorandum from B. Siegel (NRC) to W. Butler, "Organization and Staff - Clinton Power Station."
June 11, 1986	Letter from applicant informing staff of plans to modify safety parameter display system on basis of operator comments noted during September 13, 1985, test display of containment isolation valve status.
June 13, 1986	Letter from applicant informing staff of progress made in resolving issues defined in notice of deviation contained in Inspection Report 50-461/86-18 regarding instrument air system.
June 17, 1986	Letter from applicant requesting issuance and receipt of operating license by July 15, 1986, in advance of scheduled fuel load date to allow final review of license conditions and Technical Specifications before loading fuel.
June 17, 1986	Letter from applicant notifying staff of modification of nuclear system protection systems of reactor protection systems power supplies in response to NRC October 20-30, 1985, inspection concerns. Electrical protection assembly will be mounted on a separate mounting plate.

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June 18, 1986	Letter to applicant forwarding final draft Technical Specifications for review and certification. Technical Specifications are consistent with FSAR SER (NUREG-0853), and as-built facility.
June 19, 1986	Letter from applicant forwarding "Reactor Containment Building Integrated Leakage Rate Test," final report, per 10 CFR 50, Appendix J. Schematic arrangement of leakage rate measurement systems is included in the report.
June 19, 1986	Letter from applicant forwarding "NFPA Code Conformance Evaluation Report for Clinton Power Station."
June 20, 1986	Letter from applicant forwarding details of operator actions following evacuation of main control room and safe shutdown from remote shutdown panel, per request, including list of assumptions and approximate times for specific actions for scenario.
June 23, 1986	Letter from applicant forwarding additional information to satisfy requirements of TMI Action Plan Item II.F.1 on accident monitoring instrumentation, per SSER 5 (NUREG-0854). Correction factor curves for stack monitors and standby gas treatment system sample cooler capacity information are enclosed.
June 23, 1986	Letter from applicant forwarding Revision 2 to "Dynamic Qualification of Time Delay Relays" in response to May 5 and 6, 1986, requests for supplemental information on SER Outstanding Issue 7ii, "Seismic and Dynamic Qualification of Equipment."
June 25, 1986	Generic Letter 86-11 issued to all nonpower reactor licensees on distribution of products irradiated in research reactors.
June 25, 1986	Letter to applicant forwarding Technical Specification page 3/4 10-7 inadvertently omitted from June 18, 1986, transmittal of final draft Technical Specification on special test exceptions.
June 30, 1986	Letter to applicant forwarding reassessment of hazardous materials shipped near plant, based on CY85 survey data for Illinois Central Gulf Railroad Gilman Line per SSER 3 (NUREG-0853). Risks associated with railroad transportation hazards are acceptably low.
June 30, 1986	Letter from applicant forwarding amendment to application for operating license changing Technical Specifications 3/4.3.8, "Turbine Overspeed Protection System," and 3/4.7.6, "Turbine Bypass System," to reduce probability of generating a turbine missile.

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June 30, 1986	Letter to applicant advising staff that CPPR-137 expires on October 1, 1986. Request for extension should be submitted at least 30 days before expiration date.
July 2, 1986	Letter from applicant commenting on draft License NPF-55, transmitted with June 18, 1986, letter. Utility requested deferral of traversing in-core probe system preoperational testing "prior to exceeding 5% of rated reactor power," not "prior to reactor heatup."
July 3, 1986	Generic Letter 86-12 issued to all non-power reactor licensees authorized to use highly enriched uranium fuel about criteria for unique purpose exemption from conversion from use of highly enriched uranium fuel.
July 7, 1986	Letter to applicant forwarding Federal Register notice of environmental assessment and final finding of no significant impact concerning March 27 and May 29, 1986, requests to defer completion of 10 preoperational tests from prior fuel load to various licensing milestones.
July 8, 1986	Letter from applicant forwarding revised Technical Specification on low-frequency motor generator set output breaker overcurrent devices to justify deletion of molded case 600-V 250-A circuit breakers from surveillance testing.
July 8, 1986	Letter from applicant forwarding response to staff comments on FSAR Section 13.2 on shift technical advisor and supervisor training programs. Training courses will be 40 contact hours. Shift technical advisors will complete 3 months of on-the-job training.
July 9, 1986	Letter from applicant responding to staff questions on method of seismic analysis of piping subsystems to close out SSER 6. Analysis is discussed in FSAR Section 3.7.3.1.1.4. Combination of absolute sum and square root of sum of squares methods is used in the analysis.
July 10, 1986	Letter from applicant requesting change to final draft Technical Specification Table 3/4 3.7.12-1. Change involves disabling high-range iodine monitoring channel of both standby gas treatment system exhaust system level particulate iodine monitor and noble gas monitor.
July 16, 1986	Letter from applicant forwarding responses to staff questions about FSAR Chapter 3 and 4 amendments. Necessary changes will be reflected in a future FSAR amendment. Issues should be closed out in SSER 6.
July 16, 1986	Letter from applicant discussing commitment to perform control rod drive system vessel inventory makeup rate test, per NUREG-0619, "BWR Feedwater Nozzle and CRD Return Line Nozzle Cracking," and IE Open Item 85-15-01. FSAR will be amended, since test is no longer required.

July 16, 1986	Letter from applicant providing further definition of May 15, 1986, schedule for completion of control system failure reanalysis. SSER 6 evaluation is consistent with scope of reanalysis in SER outstanding Licensing Issue 15.

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APPENDIX B

REFERENCES

Bearman, P. W., and Trueman, D. M., "An Investigation of Flow Around Rectangular Cylinders," Aeronautical Quarterly, August 1972.

Bostock, B. R., and Mair, W. A., "Pressure Distribution Forces on Rectangular and D-Shaped Cylinders," Aeronautical Quarterly, August 1972.

Burns and Roe, Inc., Technical Report, "Bulk Pool Swell Impact Loads on Small Structures Above Pool Surface at Clinton Power Station," Attachment to IPC Letter U-600020 from F. A. Spangenburg (IPC) to W. R. Butler (NRC), May 16, 1985.

General Electric Co., NEDE-13426P, "Mark III Confirmatory Test Program. One-Third Scale Pool Swell Impact Tests, Test Series 5805," August 1975.

Maise, G., "Suggested Acceptance Criteria for Impact Loads on Short Mark IiI Structures Close to the Pool," Brookhaven National Laboratory, February 15, 1984.

U.S. Nuclear Regulatory Commission, Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," July 8, 1983.

---, NUREG-75/013, "Safety Evaluation of the Clinton Power Station, Units 1 and 2," March 1975.

---, NUREG-0487, "Mark II Containment Lead Plant Program Load Evaluation and Acceptance Criteria," November 1978.

---, NUREG-0661, "Safety Evaluation Report, Mark I Containment Long-Term Program. Resolution of Generic Technical Activity A-7," July 1980.

---, NUREG-0700, "Guidelines for Control Room Design Reviews," September 1981.

---, NUREG-0978, "Mark III LOCA-Related Hydrodynamic Load Definition," August 1984.

---, NUREG-1000, "Generic Implications of the ATWS Events at the Salem Nuclear Power Plant," Vol. 1 (April 1983), Vol. 2 (August 1983).

---, NUREG/CR-2913, "Two-Phase Jet Loads," January 1983.

Young, C. W., "Depth Prediction for Earth-Penetrating Projectiles," Journal of the Soil Mechanics and Foundation Division, ASCE, Vol. 95, No. SME Pro. Paper 6588, May 1969, pp. 803-817.

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APPENDIX C

UNRESOLVED SAFETY ISSUES

A-43 Containment Emergency Sump Reliability

This concern is related to the potential for degraded emergency core cooling system performance as a result of thermal insulation debris that may be blown into the suppression pool during a loss-of-coolant accident and cause blockage of the pump suction lines. In the SER, the staff concluded that Clinton can be operated before this generic issue has been resolved without endangering the health and safety of the public.

Since the SER was issued, the staff has completed its analysis of this issue which is contained in NUREG-0869, Revision 1, "USI A-43 Regulatory Analysis." The staff has concluded, as a result of this analysis, that no new requirements need to be imposed on licensees and construction permit holders. Therefore, this issue is considered resolved for Clinton Power Station, Unit No. 1.

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APPENDIX D

NRC STAFF CONTRIBUTORS AND CONSULTANTS

This SER supplement is a product of the NRC staff and its consultants. The persons listed below were principal contributors to this report.

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APPENDIX F

ERRATA TO CLINTON POWER STATION SAFETY EVALUATION REPORT

SER

Page 1-9, Table 1.2	Change Clinton recirculation pump flowrate from "35,500" to "32,500"
Page 2-1, Section 2.1.1, line 13:	Change "343,285" to "343,825"
Page 2-17, Section 2.4.1, line 8:	Change "137" to "141"
Page 2-17, Section 2.4.1, line 9:	Change "39" to "37"
Page 2-17, Section 2.4.2, line 4:	Change "334" to "335"
Page 2-31, Section 2.5.2.5, lines 3 and 4:	Change "the Regulatory Guide 1.60," to "the Regulatory Guide 1.60." Delete rest of line and first 2 words on next line. Insert: "The zero period acceleration spectrum at the foundation level is 0.10g; the zero period acceleration level at the ground level is 0.11g."
Page 2-45, Section 2.6.3.7, line 3:	Change "25-ft" to "35-ft"
Page 3-3, Section 3.2.2, line 14:	Change "Revision 2" to "Revision 3"
Page 3-4, Section 3.3.1, line 3:	Change "recurrence interval" to "mean occurrence interval"
Pages 4-2 & 3, Section 4.2.2	All references to 8 x 8 (I) should be changed to P 8 x 8 R
Page 4-7, Section 4.2.3.8, line 7:	Delete "(8 x 8 (R) fuel...latter design)"
Page 5-3, Section 5.2.2, line 1:	Change "GDC 10" to "GDC 15"
Page 5-3, Section 5.2.2	In table, change "1103" and "1123" to "1125" and "1155," respectively

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Page 5-19, Section 5.4.1, line 26:	Change "leakage from the main feedwater" to "back leakage from the reactor pressure vessel"
Page 6-9, Section 6.2.1.3, line 23:	Change "4.6°F" to "4.7°F"
Page 6-32, Section 6.4, line 32:	Change "4000 cfm" to "3000 cfm"
Page 6-34, Section 6.5.4.1, line 6	Change "4000" to "3000"
Page 7-3, Section 7.2.1, Item (1):	Change "initial fuel loading only" to "all full loading events"
Page 7-14, Section 7.3.1.5, lines 1 & 2:	Change ", any two of which can fulfill design requirements. It" to "that"
Page 7-14, Section 7.3.1.5, line 10:	Change "heater" to "header"
Page 7-30, Section 7.5.1, line 6:	Delete GDC "9" and Regulatory Guide "1.20"
Page 7-33, Section 7.5.2.2, line 5:	Change "Regulatory Guides 1.147 and" to "Regulatory Guide"
Page 7-41, Section 7.6.1, item (5), line 10:	Change "the initial fuel load" to "all fuel loads"
Page 7-42, Section 7.6.1, item (5), line 7:	Change "IRMs" to "LPRMs"
Page 8-6, Section 8.2.3, line 30:	Change "3734+19 V (93.4" to "3797±35 V (94.9"
Page 8-17, Section 8.4.4, line 7:	Change "November 3" to "November 30"
Page 8-18, Section 8.4.5, line 6:	After "are" add "analyzed, or" and delete "only"
Page 9-25, Section 9.4.5, line 22:	Delete "through a filter"
Page 9-26, Section 9.4.5, line 15	Change "The portions" to "Portions"
Page 9-26, Section 9.4.5, line 22:	Change "if available" to "during normal conditions"
Page 9-26, Section 9.4.5, line 26:	Change "atmosphere" to "turbine building"

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Page 9-26, Section 9.4.5, line 26:	Delete "one of" and "provided for each room"
Page 10-2, Section 10.2, line 28:	Change "reheat valves" to "combined intercept valves"
Page 10-2, Section 10.2, lines 29 & 30:	Change "reheat stop valve" to "intermediate stop"
Page 10-2, Section 10.2, line 30:	Change "reheat" to "combined"
Page 10-2, Section 10.2, line 32:	Change "reheat" to "intermediate"
Page 12-9, Section 12.4, line 24:	Change "Table 12.46" to "Subsection 12.4.5"
Page 16-1, item (2):*	Add "(2) HPCS/RCIC restart criteria (7.3.3.5)"
Page 16-1, item (4):	Change "4.4.2" to "4.4.1"
Page 16-1, item (5):	Change "4.4.2" to "4.4.1"
Page 16-1, item (6):	Add "(4.4.1)" at end of item**
<u>SSER 1</u>	
Page 2-3, Section 2.4.8, line 2:	Change "score" to "scour"
<u>SSER 2 through 5</u>	
Page 1-7, issue (68)	Change "Preservice" to "Inservice"
<u>SSER 5</u>	
Page 1-6, issue (38)	Change "Under review" to "Resolved in this SSER"
Page 3-7, line 5	Delete "high energy lines" and insert "reactor system piping"
Page 3-7, lines 23 & 24	Delete everything between "not...annealed" and insert "kept to a minimum."
Page 5-3 lines 12-17	Delete last two sentences of paragraph starting with "Because" and ending with "unlikely."
Page 5-3, line 45	Delete "since"

*Deleted in SSER 5.

**"(4.4.2)" was deleted in SSER 5 when wording of item was changed.

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Page 9-11, line 3	Delete everything between "memorandum... 1985" and insert "letter from C. Thomas (NRC) to H. Pfefferlan (GE), dated May 17, 1985,"
Page 17-5, line 34	Delete everything after "licensing commitment." and insert: "The staff has reviewed the applicant submittals on the issue and, based on its evaluation contained in Section 3.9.2 of this supplement to the SER, determined that this issue has been adequately resolved."

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APPENDIX I

SUPPLEMENT TO PRESERVICE INSPECTION RELIEF REQUEST EVALUATION
CLINTON POWER STATION UNIT NO. 1

AMENDMENT 1

I. INTRODUCTION

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

This evaluation is in addition to the staff review reported in the corresponding Appendix in NUREG-0853, Supplement 5. In a letter dated March 17, 1986, the applicant requested relief from an additional American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI preservice examination requirement that was determined to be impractical to perform and provided a supporting technical justification pursuant to 10 CFR 50.55a(a)(3). The staff review of the information in this letter is discussed in the following paragraphs of this report.

II. TECHNICAL REVIEW CONSIDERATIONS

For the basis of the staff review of the Clinton Power Station Unit 1 Preservice Inspection (PSI) Program and requests for relief from impractical requirements, see the corresponding section of Appendix I of NUREG-0853, Supplement 5.

III. EVALUATION OF RELIEF REQUESTS

In a submittal dated October 8, 1985, the applicant requested relief from ASME Code Section XI requirements which were determined to be not practical to perform. These relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). The staff's evaluation of these relief requests was reported in Appendix I of NUREG-0853, Supplement 5.

In a letter dated March 17, 1986, the applicant requested relief from an additional Code requirement and provided a supporting technical justification. Therefore, the staff evaluation consisted of reviewing this submittal and determining if relief from the Code requirement was justified. Pursuant to 10 CFR 50.55a(a)(3), relief from the Code requirements has been allowed for those requirements that, if implemented, would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. This preservice requirement was concluded to be impractical based on the following:

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C. Relief Request, Visual Examination of Component Supports for Class 3 Piping

Code Requirement: Article IWD-2000, Paragraph IWD-2600(c) of the 1974 Edition, Summer 1975 Addenda, of ASME Code Section XI requires that supports (restraints) and hangers for components exceeding 4-inch nominal pipe size whose structural integrity is relied upon to withstand design loads when the system function is required shall be visually examined, as a preservice examination requirement prior to initial plant startup, to detect any loss of support capability and evidence of inadequate restraint.

Code Relief Request: Relief is requested from performing the Code-required preservice visual examination on component supports for the component cooling water (CC), fuel pool cooling and cleanup (FC), control room HVAC (VC), reactor water cleanup (RT), and shutdown service water (SX) system Class 3 piping lines listed in the March 17, 1986, submittal.

Reason for Request: ASME Code Section XI, 1974 Edition including Addenda through Summer 1976 does not include Class 3 exemption criteria. The applicant states that the ISI program for Clinton Unit 1 will be based on the requirements of the 1980 Edition, Winter 1981 Addenda, or later, as required by 10 CFR 50.55a(g)(4)(i). Class 3 exemptions are included in the later Code edition and addenda. The applicant's relief request specifically identifies the lines associated with the component supports that will be exempted from the ASME Code Section XI visual examinations during ISI.

Staff Evaluation: The staff has reviewed the above information and concluded that this relief request is acceptable because updating to the requirements of later approved editions and addenda is permitted by 10 CFR 50.55a(g)(3)(v). The staff also agrees with the applicant that the ISI Program Plan for Clinton Power Station Unit 1 will be written to at least the 1980 Edition, Winter 1981 Addenda, or later, as required by the regulations and that these edition and addenda contain Class 3 exemptions for the subject lines. It is also noted that the preservice structural integrity has been assured by the nondestructive examinations performed during fabrication.

IV. CONCLUSION

On the basis of the staff review and evaluation, it is concluded that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(3), relief is allowed from these requirements which are impractical to implement.

APPENDIX L

CONFORMANCE TO GENERIC LETTER 83-28, ITEM 2.1 (PART 1)

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EGG-NTA-7177

CONFORMANCE TO GENERIC LETTER 83-28
ITEM 2.1 (PART 1) EQUIPMENT CLASSIFICATION (RTS COMPONENTS)
SELECTED GENERAL ELECTRIC BOILING WATER REACTOR PLANTS

ARNOLD
BIG ROCK POINT 1
BRUNSWICK 1 AND 2
CLINTON

R. HAROLDSEN

Published March 1986

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Idaho Falls, Idaho 83415

Prepared for the
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Washington, D.C. 20555
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FIN Nos. D6001 and D6002

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ABSTRACT

This EG&G Idaho, Inc. report provides a review of the submittals from selected operating and applicant Boiling Water Reactor (BWR) plants for conformance to Generic Letter 83-28, Item 2.1 (Part 1). The following plants are included in this review.

Plant Name	Docket Number	TAC Number
Duane Arnold	50 331	52835
Big Rock Point 1	50 155	52819
Brunswick 1	50 325	52823
Brunswick 2	50 324	52824
Clinton	50 461	--

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FOREWORD

This report is supplied as part of the program for evaluating licensee/applicant conformance to Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events." This work is being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of PWR Licensing-A, by the EG&G Idaho, Inc.

The U.S. Nuclear Regulatory Commission funded this work under the authorization B&R 10-19-19-11-3, FIN Nos. D6001 and D6002.

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1. INTRODUCTION AND SUMMARY

On February 25, 1983, both of the scram circuit breakers at Unit 1 of the Salem Nuclear Power Plant failed to open upon an automatic reactor trip signal from the reactor protection system. This incident was terminated manually by the operator about 30 seconds after the initiation of the automatic trip signal. The failure of the circuit breakers was determined to be related to the sticking of the undervoltage trip attachment. Prior to this incident, on February 22, 1983, an automatic trip signal was generated at Unit 1 of the Salem Nuclear Power Plant based on steam generator low-low level during plant startup. In this case, the reactor was tripped manually by the operator almost coincidentally with the automatic trip.

Following these incidents, on February 28, 1983, the NRC Executive Director for Operations (EDO), directed the staff to investigate and report on the generic implications of these occurrences at Unit 1 of the Salem Nuclear Power Plant. The results of the staff's inquiry into the generic implications of the Salem Unit 1 incidents are reported in NUREG-1000, "Generic Implications of the ATWS Events at the Salem Nuclear Power Plant."[1] As a result of this investigation, the Commission (NRC) requested (by Generic Letter 83-28, dated July 8, 1983[2]) all licensees of operating reactors, applicants for an operating license, and holders of construction permits to respond to generic issues raised by the analyses of these two ATWS events.

This report is an evaluation of the responses submitted from a selected group of Boiling Water Reactors (BWRs) for Item 2.1 (Part 1) of Generic Letter 83-28.

The results of the review of four individual plant responses are combined and reported on in this document to enhance review efficiency. The specific plants reviewed in this report were selected based on the convenience of review. The actual documents which were reviewed for each

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evaluation are listed at the end of each plant evaluation. The generic documents referenced in this report are listed at the end of the report.

Part 1 of Item 2.1 of Generic Letter 83-28 requires the licensee or applicant to confirm that all reactor trip system components are identified, classified, and treated as safety-related as indicated in the following statement:

> Licensees and applicants shall confirm that all components whose functioning is required to trip the reactor are identified as safety-related on documents, procedures, and information handling systems used in the plant to control safety-related activities, including maintenance, work orders, and parts replacement.

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2. PLANT RESPONSE EVALUATIONS

2.1 Duane Arnold -- 50-331 TAC No. 52835

The licensee for the Duane Arnold Energy Center (Iowa Electric Light and Power Company) responded to the requirements of Item 2.1 (Part 1) with submittals dated November 7, 1983, February 29, 1984, and December 26, 1984.

The Arnold Plant, as is common for most BWRs, does not have a defined reactor trip system; therefore, the components that are necessary to perform the reactor trip function were reviewed. This review verified that these components were identified as safety-related and that this designation was shown on the plant Q-200 Quality List.

The licensee stated that the Q-200 Quality List is the single document that defines the safety classification of components. The licensee also stated that all documents and procedures, including those related to maintenance, work orders, and parts replacement activities, rely on the Q-200 Quality List for the safety classification of components.

2.2 Conclusion

Based on the review of the licensee's submittals, we find that the licensee's responses confirm that a system exists to classify as safety-related those reactor protection system components that are needed to perform reactor trip, and this system is used to assure that such components are designated as safety-related in all relevant plant documentation. These responses, therefore, meet the requirements of Item 2.1 (Part 1) of Generic Letter 83-18, and are acceptable.

REFERENCES

1. Letter, R. W. McGaughy, Iowa Electric Light and Power Company, to H. R. Denton, NRC, November 7, 1983.

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2. Letter, R. W. McGaughy, Iowa Electric Light and Power Company, to H. R. Denton, NRC, February 29, 1984.

3. Letter, R. W. McGaughy, Iowa Electric Light and Power Company, to H. R. Denton, NRC, December 26, 1984.

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2.3 Big Rock Point -- 50-155 TAC No. 52819

The licensee for the Big Rock Point Nuclear Plant (Consumer Power Company) responded to the requirements of Item 2.1 (Part 1) with submittals dated February 2, 1984 and October 2, 1984. The submittals state that the reactor trip system components were reviewed and classified as safety-related in the licensee's "Q" listing. This listing is used as a reference when generating equipment classifications for the control of safety-related activities, such as procedures, maintenance orders, and procurement of replacement parts.

2.4 Conclusion

Based on the review of the licensee's submittals, we find that the licensee's responses confirm that the components required to trip the reactor have been designated as safety-related. In addition, the system for identifying safety-related components is used to assure that such components are designated as safety-related in all relevant plant documents. These responses, therefore, meet the requirements of Item 2.1 (Part 1) of Generic Letter 83-28 and are acceptable.

REFERENCES

1. Letter, R. M. Krich, Consumers Power Company, to D. M. Crutchfield, NRC, February 2, 1984.

2. Letter, J. L. Kuemin, Consumers Power Company, to Director NRR, NRC, October 2, 1984.

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2.5 Brunswick 1 and 2 -- 50-325 and 50-329 TAC Nos. 52823 and 52824

The licensee for Brunswick Units 1 and 2 (Carolina Power and Light Company) responded to the requirements of Item 2.1 (Part 1) in a submittal dated November 7, 1983. The submittal describes the system used to determine which components are safety-related. Those activities, such as maintenance and procurement of replacement parts, which affect Q-List (i.e., safety-related) components, are required to be performed using procedures which are specifically intended for the control of Q-List-related activities.

2.6 Conclusions

Based on the review of the licensee's submittal, we find that the licensee's reponse confirms that the components required to trip the reactor are identified as safety-related, and that documents used to initiate design, maintenance, or procurement require identification of safety-related components. The licensee's response, therefore, meets the requirements of Item 2.1 (Part 1) of Generic Letter 83-28, and is acceptable.

REFERENCES

1. Letter, P. W. Howe, Carolina Power and Light Company, to D. G. Eisenhut, NRC, November 7, 1983.

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2.7 Clinton Power Plant 50-461 (OL)

The applicant for the Clinton Nuclear Plant (Illinois Power Company) responded to the requirements of Item 2.1 (Part 1) in a submittal dated October 1, 1984. The response states that the applicant reviewed the classification of those components required to trip the reactor and identified two components that had not previously been classified as safety-related. These components were the limit switches on the main steamline isolation valves and the backup scram valves. The limit switches have now been classified as safety-related; the applicant provided a justification for a classification of nonsafety-related for the backup scram valves.

Tht statement of justification, provided by General Electric through the BWR Owners' Group (BWROG), is as follows:

> Since the backup scram system provides no increase in safety margin, the system is not classified as safety related. Failure to operate will, therefore, not prevent a scram. The backup scram system is intended to be a diverse system energized to operate versus the scram system which is de-energized to function. The Backup Scram System meets the single failure criterion (see NUREG-1000, Vol. 1, Section 3.1.2.5).

The staff has accepted the nonsafety classification of backup scram valves.

The applicant also reviewed station procedures and verified that activities that affect any safety-related components are classified as safety-related. However, when parts which are being procured are subcomponents, the classification may not have been predetermined. In such cases, the criteria of FSAR section 3.2 is used to classify the subcomponent, and the part is then entered on the classification Q List.

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2.8 Conclusion

Based on the review of the applicant's submittal, we find that the applicant's response confirms that the components required to trip the reactor are identified as safety-related and that the system for identifying safety-related components is used to assure that these components are designated as safety-related in all relevant plant documents. The licensee's response, therefore, meets the requirements of Item 2.1 (Part 1) of Generic Letter 83-28, and is acceptable.

REFERENCES

1. Letter, F. A. Spanenberg, Illinois Power Company, to A. Schwencer, NRC, October 1, 1984.

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3. GENERIC REFERENCES

1. Generic Implications of ATWS Events at the Salem Nuclear Power Plant, NUREG-1000, Volume 1, April 1983; Volume 2, July 1983.

2. NRC Letter, D. G. Eisenhut to all Licensees of Operating Reactors, Applicants for Operating License, and Holders of Construction Permits, "Required Actions Based on Generic Implications of Salem ATWS Events (Generic Letter 83-28)," July 8, 1983.

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APPENDIX M

CLINTON QUALITY ASSURANCE REPORT

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CLINTON QUALITY ASSURANCE REPORT

Introduction

In the March 9, 1982, letter from P. Shewmon, chairman of the ACRS, to NRC Chairman N. Palladino (contained in SSER 1), the ACRS asked to be informed of the applicant's restructuring of the construction and operations quality assurance and quality control organization. The request came in response to NRC staff concerns identified during the period February-March 1981 when some aspect of safety related work had been stopped because of quality related problems. This report discusses some of the actions taken by the applicant to correct those problems. This report also describes subsequent NRC inspection activities at Clinton including staff findings of quality assurance and construction deficiencies and the actions taken by the applicant to correct them.

Quality Assurance Program

Illinois Power Company is responsible for the establishment and implementation of the Quality Assurance Program for Clinton Power Station, a composite effort consisting of its own Quality Assurance Program augmented by the quality programs of its major contractors. Each organization maintains a quality program which monitors and audits to ensure total coverage and compliance. The Illinois Power Manager of Quality Assurance reports to the Vice President in charge of managing and coordinating nuclear programs. The Manager of Quality Assurance has responsibility for establishing quality program requirements, verifying program implementation, and measuring the overall effectiveness of the program. The Manager of Quality Assurance also has the authority to stop unsatisfactory work and prevent further processing, delivery, or installation of nonconforming materials.

Illinois Power assesses the effectiveness of its Quality Assurance Program by trending conditions adverse to quality. Inputs that are trended include nonconformance reports, audit findings, and surveillance findings. Data are evaluated for impact on construction and operation. A report of trends is forwarded monthly to senior management. Negative trends are noted and fed back to departments for personnel reorientation, training or retraining to correct adverse conditions associated with equipment, material, processes, procedures, or activities. Within a respective department the manager is held accountable for implementation of corrective action.

There are three basic elements in the Illinois Power Quality Assurance Program that directly apply to the control of contractor performance. First, a review is made of the contractor's quality program and organization to ensure that requirements of 10 CFR 50 Appendix B are met and consistent with the applicant's Quality Assurance Program. Second, planned audits and surveillances verify that contractors are adequately implementing their quality programs. Third, contractors are required to implement requirements of their quality programs that ensure prompt corrective action for conditions adverse to quality. In the event that effective corrective action is not promptly taken, Illinois Power has the necessary provisions in its Quality Assurance Program to require the contractor to stop work until satisfactory

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resolution of the condition adverse to quality is attained. Since the start of construction there have been 21 stop work orders issued by Illinois Power or its contractors; ten of the orders resulted from NRC inspections.

Stop Work, Recovery, and Restructuring of Quality Programs

Significant deficiencies in Illinois Power's Quality Assurance Program and site construction practices were found by Region III staff in February 1981. An Immediate Action Letter was issued in March 1981 because of the deficiencies. Cited problems were identified with seismic Category I large bore pipe supports and restraints design, fabrication, installation, and inspection.

Illinois Power took action to correct the deficiencies. Those actions included establishment of a program to control installation of pipe hangers, indoctrination and training of quality control, quality assurance, and construction personnel, and trial installations and inspections to ensure effective program implementation.

More serious quality assurance problems at the Clinton Station surfaced in December 1981. The resident inspector received a number of allegations from electrical inspectors employed by Baldwin Associates, the prime contractor. Review of the allegations resulted in a Region III investigation begun in January 1982. It was determined that Baldwin Associates had not properly implemented the approved quality program for electrical raceways. Significant deficiencies and nonconformances were identified by contractor inspectors but had not been formally documented and resolved through established reporting procedures. As a result of the findings, in January 1982, all safety related electrical work was ordered stopped by Illinois Power and in October 1982, NRC imposed a $90,000 Civil Penalty for two violations of NRC requirements: breakdown in the Quality Assurance Program and intimidation of quality control personnel.

Region III and Office of Nuclear Reactor Regulation representatives met with Illinois Power management in January 1982 to discuss the stop work order and Illinois Power's recovery plan. Region III management visited the site and a Confirmatory Action Letter was issued by Region III that same month. NRC staff concerns included the quality assurance/quality control organizational structure, lack of Illinois Power quality assurance involvement in construction of the plant, weaknesses in identifying root causes of problems, and the lack of prompt corrective actions. Additional meetings between Region III and Illinois Power have been held since then on a recurring basis.

Several other stop work orders have been issued by Illinois Power or its contractors since the electrical problems were first identified. Work on the refueling bellows was stopped in February 1982, and procurement of spare and replacement parts was stopped in March 1982. Six stop work orders were issued by Illinois Power in June 1982 after it was determined by Region III that quality control inspection was not keeping pace with ongoing construction.

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The stop work orders included heating, ventilation, and air conditioning work; first attachment welds associated with heating, ventilation, and air conditioning components; electrical conduit; electrical equipment installation; electrical instrumentation; and structural steel. A Confirmatory Action Letter was sent by Region III to Illinois Power in September 1982. The letter stipulated that Illinois Power submit a master management plan showing the entire quality recovery program including allocation of manpower resources, organizational interfaces, and a program for verification of items already installed and inspected. Non safety related air conditioning work was stopped during August 1982. (It should be noted that several other stop work orders issued by Illinois Power or its contractors were not included under the Recovery Plan. Stop work orders are standard construction management tools used to exact full cooperation from site contractors.)

Region III verified implementation of the Confirmatory Action Letter commitments and restructuring of the Illinois Power Quality Assurance Program before any of the stop work orders were lifted by Illinois Power. The following significant changes were made:

*** A Vice president was hired and placed on site to take charge and direct quality assurance, engineering, start-up, and operations. This move greatly enhanced communications with site managers and increased their ability to address quality issues and ensure prompt action.

*** The engineering firm of Stone & Webster was retained by Illinois Power as first line management in support of construction. Several Illinois Power and Baldwin Associates personnel involved prior to the stop work orders no longer are employed in positions of authority in either quality assurance/control or construction. Increased emphasis was placed on planning, development, and implementation of detailed schedules supporting engineering, construction, and inspection. Tracking systems were developed to assure positive progress on planned and scheduled actions. Backlogs were reduced for nonconformance report dispositioning and implementation, and computerized tracking systems were developed.

*** The Illinois Power quality organization was changed to a more functional mode including quality engineering, audits, and surveillance. The staff increased from 25 to 120. (There are currently more than 300.) The Baldwin Associates staff also increased from 120 to 370. (There are currently more than 900). Illinois Power's surveillance of ongoing work was greatly enhanced. Illinois Power assumed inline review responsibility of Baldwin Associates' procedures, job instructions, and nonconformance reports. Trends that develop from audit and surveillance findings, and nonconformance reports are reviewed and analyzed on a monthly basis by senior management personnel.

*** Illinois Power developed and implemented an enhanced program for corrective action. Elements of corrective action were manifested throughout the project in various procedures and instructions. The source of the requirements came from the newly established Corporate Nuclear Procedures.

*** A consultant was hired to evaluate the overall site training programs for both Illinois Power and Baldwin Associates. As a result, both programs were extensively modified.

*** Baldwin Associates job instructions and quality control checklists were compared and revised as appropriate to assure that the installer and inspector used the same tolerances and acceptance criteria.

All stop work orders were lifted by Illinois Power by December 1983. Each area affected by a stop work order was released only after Region III verified by review and inspection that the recovery plan was in place and effective. Region III assured itself that implementing procedures were in place, personnel were trained to the procedural requirements, and Illinois Power had assured itself that work was ready to restart. Region III inspectors verified that "dry runs" of activities had been performed where required.

Overinspection Program

The management meetings between Region III and Illinois Power held in 1982 resulted in Illinois Power's commitment to inspect a portion of work completed prior to July 1982, before issuance of the stop work orders and subsequent recovery plans in order to verify the adequacy of the plant's physical construction. Illinois Power originally committed to inspect approximately 20% of structural steel; mechanical equipment; electrical raceway and supports; heating, ventilating, and air conditioning; large and small bore piping and supports; and instrumentation. Verification inspections began in August 1982, but were stopped by Illinois Power in October 1982 because Region III had determined that Illinois Power had not properly planned the activities or trained the inspectors. Stone and Webster personnel became involved with verification activities at that time. Illinois Power submitted an Overinspection Program Plan to Region III in November 1982. The plan described a complicated series of inspections including normal first line quality control inspections by Baldwin Associates; verification inspections by Baldwin Associates quality assurance; and overinspections by Illinois Power quality assurance. The Overinspection Program Plan was a statistically based random sample inspection based on Military Standard (MIL-STD)-105D, "Sampling Procedures and Tables for Inspection by Attributes". The plan was verified by Illinois Power, Stone & Webster, and NRC to produce 95% assurance that at least 95% of the items in a lot were not defective. The Overinspection Program (verification inspections) resumed inspection activities in September 1983.

Inspections of the Overinspection Program to verify its implementation have been accomplished by Region III on several occasions. Areas inspected include welding; piping and mechanical supports; electrical raceway; structural steel; heating, ventilation, and air conditioning; and the programatic elements of audit and surveillance. Two items of noncompliance were identified in the electrical area regarding completeness of vendor documentation and storage of materials. Both items were of minor significance.

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Illinois Power has determined that none of the several thousand discrepant attributes identified during overinspection has any significance to safety. Review by Region III of overinspection data and engineering evaluations for large bore piping and mechanical supports substantiate Illinois Power's conclusion. A meeting was held during April 1985 in Region III to discuss Illinois Power's progress with overinspection and Illinois Power's proposed termination of overinspecting large bore piping and mechanical supports. The proposal was concurred in by Region III in July 1985. It is anticipated by Region III that Illinois Power will submit additional requests to terminate overinspection in other areas. Each request will be reviewed on its own merits.

Overall, inspection data show that work done after 1982 has improved. The areas of structural steel, Augmented D piping and supports, radiation waste systems, and heating, ventilating, and air conditioning have not been evaluated.

Independent Design Review

In May 1984, Illinois Power submitted a plan to the NRC for an independent design review of the Clinton Power Station. The review was intended to provide the NRC with additional assurance that the design of Clinton was consistent with the design description in the Final Safety Analysis Report and Safety Evaluation Report and its supplements. The review was started in July 1984 by Bechtel Corporation and was completed in December of the same year. NRC's Office of Inspection and Enforcement ensured that the review was conducted in accordance with the approved plan as documented in a special inspection report dated November 1984. The special inspection included evaluations of the review team's walkdown activities and the comprehensiveness of the design reviews being conducted. The final Independent Design Report was issued by Bechtel Corporation in January 1985. The report's conclusion was that the design work which was reviewed satisfied licensing commitments and met acceptable standards of technical adequacy; however, there were discrepancies with undocumented engineering judgements, control of document changes, and control of design interfaces. The Office of Inspection and Enforcement substantiated Bechtel's conclusion that none of the discrepancies was significant enough to require an independent design review in other systems. Region III conducted an inspection at Sargent & Lundy, the architect engineer, in May 1985 to verify implementation of the corrective actions agreed to as a result of the final Independent Design Review Report. Results of the Region III inspection were favorable and will be summarized in Supplemental Safety Evaluation Report (SSER) Amendment 5.

Petition To Intervene

Petitions to intervene were filed in 1980 by the Prairie Alliance and the State of Illinois Attorney General. An Atomic Safety and Licensing Board was established in 1981 and admitted 12 contentions including quality assurance. The number of contentions was ultimately reduced to three by negotiations; however, quality assurance issues remained to be settled. Quality assurance issues were the subject of extensive discussions and exchanges of information among the applicant, the State, and NRC. Illinois Power submitted a "Summary of Quality Improvements and Confirmatory Actions" (QICA) which described the programs and plans for action to address the concerns raised by the contention

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on quality. The programs and plans included a record verification program, a Final Safety Analysis Report verification program; third party audits; special programs including seismic analyses for as-built safety related piping systems walkdown program, seismic interaction analysis program, electrical separation program, and fire protection program; a configuration program; a system turnover and start-up testing program; the overinspection program; and the independent design review. A meeting was held in December 1984 at Region III's office between NRC and representatives of the State of Illinois Attorney General. The purpose of the meeting was to discuss NRC inspection activities and the methods used or contemplated to inspect the previously described Illinois Power quality related plans and programs. Specific matters discussed were the overinspection program, the independent design review, the proposed NRC Construction Appraisal Team (CAT) inspection, and the Operations Quality Assurance Program.

Region III responded in writing to the Illinois Attorney General in January 1985 regarding the NRC actions planned or taken to verify the various programs discussed in Illinois Power's QICA.

Based on negotiations and the previously described programs, plans and meetings, a Joint Stipulation was signed in January 1985 between Illinois Power, the State of Illinois Attorney General, and the Nuclear Regulatory Commission. The Joint Stipulation allows the Illinois Attorney General to participate in matters relating to those quality related issues previously discussed. As a result, the remaining contentions have been withdrawn and Atomic Safety and Licensing Board proceeding terminated. To date, the Illinois Attorney General's office has attended meetings and actively participated in matters related to the independent design review, overinspection, and the CAT inspection.

Construction Appraisal Team Inspection

The CAT inspection was discussed during the December 1984 meeting held in the Region III office with Illinois Power, the State of Illinois Attorney General, and NRC staff. The meeting was a strong force in getting the CAT inspection accomplished. Approximately 2500 inspection hours were utilized during the inspection conducted during May and June 1985. The CAT inspection included concrete placement and testing; electrical raceways, supports, cables and equipment; pipe, pipe supports and restraints; expansion anchors; heating, ventilating and air conditioning; welding; nondestructive examinations; and structural steel. Also included were the general quality aspects of procurement, maintenance, material traceability, and processing field changes and nonconforming conditions. Some items selected for inspection included those which had been completed as part of the overinspection program. The CAT identified problems with the program for inspection of electrical cable separation. Other concerns include: unqualified switchboard wire used by plant maintenance personnel in environmentally qualified panels; rejectable indications on radiographs of welds made on the containment liner and some vendor supplied tanks; discrepant records of soils work; untraceable/unspecified

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materials used to fabricate vendor supplied fasteners on mechanical equipment; and deficient wiring/workmanship in vendor supplied electrical panels. These findings were discussed at the exit meeting held at the site in June 1985. The findings will be documented in the CAT inspection report which should be published in August 1985. Region III will followup on all problems identified and on Illinois Power's corrective action.

Quality Assurance Program for Preoperational Testing and Plant Operations

The Operations Quality Assurance Program was discussed during the December 1984 meeting held in Region III between Illinois Power, the State of Illinois Attorney General, and NRC staff. Region III inspected Illinois Power's Quality Program for preoperational testing between November 1984 and January 1985. Ten minor deficiencies were brought to Illinois Power's attention as a result of the inspection. Preoperational testing is currently in progress and no significant deficiencies have been identified. Preoperational testing is currently behind schedule and could become a significant item in the critical path of fuel loading which is currently scheduled for January 1986.

Region III is currently reviewing Illinois Power's Quality Program for start-up and plant operations. No significant problems have been identified to date. All critical plant management positions have been filled. The first group of candidates has completed operator licensing examinations with typical results.

Systematic Assessment of Licensee Performance (SALP)

The SALP program systematically evaluates the performance of licensees and license applicants in all facets of facility construction and operation to ensure that public health and safety is not compromised. SALP involves an integrated subjective assessment of the applicant by NRC management utilizing inputs from resident inspectors, regional inspectors, and appropriate NRC headquarters personnel. SALP evaluations and related management meetings with applicants for Near Term Operating License plants are heavily oriented toward construction practices and construction quality assurance.

Performance of Illinois Power Company at Clinton has been evaluated four times via the SALP process, twice since the more serious quality related problems surfaced in late 1981.

The first SALP addressed Illinois Power's performance during the period July 1979 to June 1980. Overall performance was considered adequate. Increased NRC attention was recommended for the areas of management, training, and quality assurance.

The second SALP, for the period July 1980 through September 1981, concluded that overall regulatory performance was marginal. It was observed that there was an increase in the number and seriousness of quality issues directly attributable to Illinois Power's reluctance to take adequate and lasting corrective action on identified problems. It was further observed that there was a lack of experience in the project organization's management. Overall, quality assurance was marginal. Piping systems and supports was rated minimally acceptable. Electrical power and distribution was rated below minimally acceptable; no electrical work was in progress. RIII's assessment included a recommendation that Illinois Power reassess their commitment to quality beginning with upper management, and ensure that supervisors and employees were likewise committed.

During the third SALP period, October 1981 through September 1982, the major NRC observation was that there were two distinct phases, one of minimally acceptable past performance, and the other which represented efforts to fully scope past construction deficiencies and initiate appropriate corrective actions through a regulatory improvement program. The overall performance rating had improved or remained the same in all areas except quality assurance which was minimally acceptable. Electrical power and distribution did not receive a rating because it was not at least minimally acceptable. Electrical work had already been stopped to correct significant quality assurance deficiencies. Region III observed that there was positive evidence in the second half of the assessment period to indicate a rededication to quality assurance. Even though there were problems with Illinois Power transforming their regulatory program from paper to action, Region III was encouraged by the results achieved towards the end of the assessment period.

The fourth and most recent SALP period addressed Illinois Power's performance during the period October 1982 through February 1984. The major observation was that performance improved or remained the same; all rated functional areas were rated satisfactory. A major observation was the rating of satisfactory in electrical power and distribution. Region III observed that even though problems continued, many of the discoveries resulted from Illinois Power's efforts in increasing levels of experience, improving procedures, improved training, and increased quality awareness by personnel.

The next SALP will address the period March 1984 through August 1985. The SALP report should be issued in November 1985. To date, Illinois Power performance in all rating areas appears satisfactory.

History of Inspection and Enforcement

Since issuance of the Construction Permit in February 1976 the NRC has conducted 214 inspections at the Clinton site through May 1985. To accomplish the inspection program over 14,865 inspector-hours of direct inspection effort have been expended. 129 items of noncompliance have been identified by NRC inspectors at Clinton, which is average for construction sites in Region III.

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No orders have been issued to Clinton. One Civil Penalty in the amount of $90,000 was imposed in 1982 for failure to document and implement a quality assurance program in the electrical area, and because quality control inspectors did not have sufficient freedom to identify quality problems and were not independent of cost and schedule.

There have been 57 RIII inspections since lifting the stop work orders in late 1983 through May 1985, involving 4693 inspection hours. Those inspections resulted in the identification of 11 items of noncompliance. None of the 11 identified noncompliances was considered derivative from the specific Quality Assurance Program deficiencies that caused the Immediate/Confirmatory Action Letters. Overall regulatory performance at Clinton has been good; that is, the number and type of noncompliances since late 1983 have been below the average for construction projects at the same stages of completion. This reflects the general success of Illinois Power's quality improvements and confirmatory actions taken in 1983.

Tables 1 & 2 summarize the NRC inspection effort and NRC inspection findings at Clinton since issuance of the Construction Permit. Perturbations in the inspector-hours listed and the noncompliances cited were caused by major findings in late 1981 and early 1982 which caused several stop work orders in 1982. The assignment of three additional resident inspectors and the recent NTOL status of the plant account for the recent increase in NRC inspection hours.

Conclusion

Overall, Region III finds the Illinois Power Quality Assurance Program for construction and preoperational testing acceptable. The applicant has been responsive to correcting previously identified construction problems. Illinois Power management changes have been positive. Management recognizes the necessity for their continued attention to assure quality construction and performance. The positive results of Region III inspections and other reviews indicate the effectiveness of restructuring the quality organization and other corrective actions taken by Illinois Power. The Quality Assurance Program is being effectively implemented by Illinois Power and its contractors.

Region III is continuing its review of the Quality Assurance Program for operations. Region III will continue inspecting to ensure that the applicant implements effective programs for review and audit of site contractor performance. Region III will assure that the applicant corrects identified deficiencies and any negative trends in performance by their contractors.

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TABLE 1

NRC INSPECTIONS

Period	Inspections	Hours	Noncompliances	Hours/Item
1975	1	8	0	---------
1976	6	78	3	26
1977	12	243	14	17
1978	7	369	10	7
1979	12	555	4	139
1980	27	1499	24	63
1981	32	2352	34	69
1982	25	1952	17	115
1983	24	2292	13	176
1984	43	3358	9	373
1985	25	2159	1	2159
Total	214	14,865	129	*

*Through May 1985

*Hours/noncompliance
14,865/129=115

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TABLE 2

NONCOMPLIANCE DISTRIBUTION

10 CFR 50 Appendix B Criterion		Cited Noncompliances (%)
I	Organization	1.5
II	QA Program	2.5
III	Design Control	7.5
IV	Procurement Document Control	0.8
V	Instructions, Procedures & Drawings	32.6
VI	Document Control	3.0
VII	Control of Purchased Material, Parts Components	2.5
VIII	Identification & Control of Materials, Parts and Components	0.8
IX	Control of Special Processes	12.5
X	Inspection	6.5
XI	Test Control	0.0
XII	Control of Measuring & Test Equipment	1.5
XIII	Handling, Storage & Shipping	8.0
XIV	Inspection, Test & Operating Status	0.8
XV	Nonconforming Materials, Parts or Components	6.5
XVI	Corrective Action	8.0
XVII	QA Records	2.5
XVIII	Audits	2.5

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APPENDIX N

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
RELATING TO DEFERRALS BEYOND FUEL LOAD OF CERTAIN PREOPERATIONAL TEST ITEMS
FOR CLINTON POWER STATION, UNIT NO. 1

1.0 INTRODUCTION

The applicant has proposed deferring a number of acceptance and/or preoperational test items for various periods beyond fuel load. The request was made by letter dated March 12, 1986, and was supplemented by specific exemption requests and additional information provided by letters dated March 27 and May 29, 1986. Preoperational testing of the leak detection system, portions of the containment monitoring system, as well as portions of the heating, ventilation, and air conditioning system would be completed before initial criticality. Preoperational testing of the offgas system would be completed before reactor pressure vessel headset before reactor heatup. Acceptance testing of the turbine electrohydraulic control system and preoperational testing of the solid radwaste system, and portions of the heating, ventilation, and air conditioning system tests would be completed before reactor heatup. Preoperational testing of the fuel pool cooling and cleanup system, the traversing incore probe (TIP) system, and of the fuel handling system would be completed before exceeding 5% of rated reactor power.

2.0 EVALUATION

The staff has reviewed the conditions and special circumstances that must be met before an exemption can be made as listed in of 10 CFR 50.12. The staff has concluded that the applicant meets these conditions in special circumstances. The conditions and circumstances that will allow for a temporary exemption of the subject general design criteria (GDC) as they pertain to nine of the systems discussed below:

(1) Conditions:

(a) Consideration of the proposed exemptions is provided for by existing regulations.

(b) The proposed exemptions do not pose any significant degradation in the security and common defense of the United States.

(c) As determined in SSER 6, the deferral requests do not present a risk to the health and safety of the public.

(2) Special Circumstances

There are six special circumstances, each taken individually, that justify granting an exemption as listed in 10 CFR 50.12(a)(2). The applicant stated

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that one of these circumstances, as described below, applies to all nine systems.

As a special circumstance, the general design criteria applicable to systems do not need to be applied when the operating conditions are such that the intended purpose for the criteria is met without the systems. The staff's evaluation is summarized as follows:

(a) This circumstance is applicable to the deferral of the acceptance testing of the turbine electrohydraulic control (EHC) system until after fuel load, but before reactor heatup. The EHC system is not required to be operable before the plant is placed in the operating mode. The applicant has committed to complete the EHC acceptance test before placing the plant in the operating mode. Therefore, this circumstance warrants granting the exemption pertaining to the EHC system.

(b) This circumstance is applicable to the deferral of completing the preoperational testing of traversing incore probe (TIP) system until before exceeding 5% of rated power. The TIP system is not required to be operable before the plant is placed in this operating mode. Therefore, this circumstance warrants granting the exemption to the TIP system.

(c) This circumstance is applicable to the deferral of completing the preoperational testing of the offgas system until the reactor vessel head is in place and head bolts are properly tensioned. Because there is no steam generated at this stage, there is no need for the offgas system. Therefore, this circumstance warrants granting the exemption pertaining to the offgas system.

(d) This circumstance is applicable to the deferral of preoperational testing of portions of the containment monitoring system until after fuel load but before initial criticality. During open vessel testing, the reactor coolant temperature is maintained below 140°F. If a loss-of-coolant accident were to occur, the containment pressure and humidity should not rise significantly, there should be no formation of hydrogen, and there should be no appreciable quantities of fission products present in the fuel. Thus, monitors for these parameters are not needed before initial criticality and this circumstance warrants granting the exemptions pertaining to the containment monitoring system.

(e) This circumstance is applicable to the deferral of preoperational testing of the leak detection system until after fuel load but before initial criticality. Until initial criticality is achieved, significant buildup of radioactive fission products in the core should not occur and there should not be any significant heat generated in the core. Thus, the monitoring capabilities of the leak detection system are not required before initial criticality and this circumstance warrants granting the exemptions pertaining to the leak detection system.

(f) This circumstance is applicable to the deferral of preoperational testing of portions of the fuel pool cooling and cleanup (FC) system until after fuel load, but before exceeding 5% of rated reactor

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power. Because the initial core will consist of only new, unirradiated fuel, there should not be any significant radiological consequences from a fuel handling accident and there should not be any significant decay heat to be removed. Thus, there is no need for the FC system to be operational before exceeding 5% of rated reactor power. Therefore, this circumstance warrants granting the exemptions pertaining to the FC system.

(g) This circumstance is applicable to the deferral of preoperational testing of portions of the fuel handling (FH) system until after fuel load but before exceeding 5% of rated reactor power. Because the initial fuel load will be performed under dry conditions, there is no need for testing the FH system under wet conditions before exceeding 5% of rated reactor power. Therefore, this circumstance warrants granting the exemptions pertaining to the FH system.

(h) This circumstance is applicable to the deferral of in-place filter testing of the control room heating, ventilation, and air conditioning (HVAC) system until before initial criticality. Since there should not be any significant fission and/or activation products in either the primary coolant system or the ventilation system at this stage, there is no need for the in-place filter testing of this system before initial criticality. Therefore, this circumstance warrants granting the exemption pertaining to the control room HVAC system.

(i) This circumstance is applicable to the deferral of testing and balancing of portions of the heating, ventilation, and air conditioning (HVAC) systems. The proposed deferral includes the auxiliary building HVAC system and drywell purge system preoperational testing, final air balancing of various HVAC systems, and in-place testing of various HVAC filters beyond the fuel load date, but before primary system heatup. Since there should not be any significant fission and/or activation products in either the primary coolant system or the ventilation system at this stage, there is no need for final testing and balancing of these systems before heatup. Therefore, this circumstance warrants granting the exemptions pertaining to the HVAC system.

An exemption from GDC requirements is not required in the case of the solid radwaste system. The staff accepted in this supplement to the SER the use of the Associated Technology Incorporated (ATI) transportable radwaste system instead of the permanently installed radwaste system at Clinton. Since the ATI system has been found to satisfy GDC requirements, no exemption is required for deferral of testing of the permanently installed radwaste system.

2.1 Turbine Electrohydraulic Control (EHC) System

The applicant requests deferr ' of the acceptance testing of the EHC system until after fuel load but before reactor heatup. The EHC system includes the turbine stop-valve position switches that supply a scram signal to the reactor protection system, and thus GDC 29 is applicable. However, before reactor heatup, the reactor coolant temperature is less than 200°F and steam is not present in the main steam lines. Hence, there should be no need to initiate a scram from stop-valve closure. Thus, the applicant's request is acceptable and an exemption from the requirements of GDC 29 will be granted.

2.2 Traversing Incore Probe (TIP) System

The applicant requests deferral of completing the preoperational testing of the TIP system until before exceeding 5% of rated reactor power. The TIP system is used to calibrate the local power range monitor (LPRM) system which is input to the average power range monitor (APRM) system. However, this calibration is required only prior to exceeding 25% power by the Technical Specifications. Therefore, deferral of the TIP preoperational test until prior to exceeding 5% of rated reactor power is acceptable. The TIP system is one of the systems that provides instrumentation to monitor variables and systems over their anticipated ranges of normal operation, and thus, GDC 13 is applicable. Thus, an exemption from the requirements of GDC 13 for the TIP system is requested by the applicant. Because the TIP system is not required to be operable until after 5% power is reached, an exemption from the requirements of GDC 13 until exceeding 5% of rated reactor power will be granted for the TIP system.

2.3 Offgas System

The applicant requests deferral of the completion of preoperational testing of the offgas system beyond the fuel load date, but before the installation of the reactor vessel head and the tensioning of the head bolts. The offgas system is one of the systems that controls the release of radioactive gaseous effluents, and thus, GDC 60 is applicable. The staff finds that because the offgas system is not needed until steam is being generated, the applicant's request is acceptable and an exemption from the requirements of GDC 60 will be granted.

2.4 Containment Monitoring (CM) System

The applicant requests deferral of those portions of the CM preoperational test related to the humidity monitors, containment and drywell hydrogen/oxygen concentration monitors, containment pressure monitors, and suppression pool and drywell excess flow instrument line check valves until after fuel load, but before initial criticality. These portions of the CM system pertain to containment atmosphere cleanup, and thus, GDC 41 is applicable. During open vessel testing the reactor coolant temperature is maintained below 140°F and decay heat is not significant. Therefore, containment pressure and humidity should not increase significantly following a loss-of-coolant accident. Also, at these temperatures it is not possible to generate appreciable amounts of hydrogen or oxygen.

Thus, there is no need for these monitoring systems to be required before initial criticality, the applicant's request is acceptable, and an exemption from the requirements of GDC 41 will be granted.

The applicant also requested deferral of preoperational testing of the containment high-range gamma radiation monitors until after fuel load, but before initial criticality. This proposed deferral is a deviation from GDC 64 as interpreted by the guidance contained in NUREG-0737. However, the staff notes that before initial criticality, there should not be appreciable quantities of fission products present in the fuel. Therefore, the staff finds that deferral until before initial criticality is acceptable and an exemption from the requirements of GDC 64 will be granted.

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2.5 Leak Detection (LD) System

The applicant requests deferral of the LD system preoperational testing until after fuel load, with completion scheduled before initial criticality. The reactor coolant pressure boundary leakage detection system includes (a) the drywell atmosphere particulate radioactivity monitoring system, (b) the drywell sump flow monitoring system, (c) the drywell atmosphere gaseous radioactivity monitoring system, and (d) the drywell air coolers condensate flow rate monitoring system. These systems consist of temperature, pressure, flow, airborne gaseous and particulate fission product sensors and process radiation sensors, with associated instrumentation to indicate and alarm leakage from the reactor coolant pressure boundary. The leak detection system is addressed by the guidelines of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," and GDC 30, "Quality of Reactor Coolant Pressure Boundary" of 10 CFR 50. GDC 30 requires testing of the components of the leak detection LD system to ensure system operability. The underlying purpose of the GDC is to minimize, by leakage detection and location using the LD system, the effects of coolant leakage that could threaten the ability to cool the reactor core adequately. GDC 64, "Monitoring Radioactivity Releases," is also applicable.

The staff has determined that until the reactor attains initial criticality, significant fuel exposure or buildup of radioactive fission products in the core should not occur. Hence, there should not be significant heat generation in the core from the fuel or the fission products. Also, there should not be significant buildup of radioactive fission products in the coolant. For the above reasons, the staff agrees with the applicant that core cooling and components of the LD system required to monitor radioactivity will not be required until initial reactor criticality is reached. The staff notes that by completing the system testing before initial criticality, the applicant will meet the requirement of Clinton Technical Specification 3/4.4.3.1, which states that three leak detection systems (a, b, and either c or d identified above) have to be operable in plant operational conditions 1, 2, and 3.

Thus, the applicant's request is acceptable and exemptions from the requirements of GDC 30 and 64 will be granted.

2.6 Fuel Pool Cooling and Cleanup (FC) System

The applicant requests deferral until after fuel load of that portion of the FC system preoperational phase test related to the demonstration of design capability to maintain and alter pool water levels. GDC 61, "Fuel Storage and Handling and Radioactivity Control," requires, in part, that the fuel storage system be designed to prevent significant reduction in fuel storage coolant inventory under accident conditions."

The initial core will be loaded into the reactor under dry conditions, i.e., there will be no water in the spent fuel pool. The initial core will consist of only new, unirradiated fuel. Therefore, all fuel handling accidents, such as dropping a fuel bundle, should have a minimum effect and should not result in any significant releases of radioactivity. New fuel does not produce any significant amounts of heat. Therefore, since there should not be significant radiological consequences of a fuel handling accident, and since there should not be decay heat to be removed, the staff concludes that the spent fuel pool cooling and cleanup system need not be operational during the initial loading of fuel into the reactor.

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Since the spent fuel pool cooling and cleanup system should not be needed to mitigate accidents during the initial core loading, the applicant's request to defer the preoperational testing of the system's capability to control water level until after fuel loading, but before exceeding 5% of rated reactor power, is acceptable. To ensure that significant fuel handling accidents at very low power are precluded, this limitation should be expanded to read "before exceeding 5% power or before removal of the reactor pressure vessel head after initial criticality." Thus, the applicant's request, as modified by the staff, is acceptable and an exemption from the requirements of GDC 61 will be granted.

2.7 Fuel Handling (FH) System

The applicant requests deferral until after fuel load of that portion of the FH system preoperational phase test related to transfer of fuel bundles under wet loading conditions. GDC 61, requires, in part, that the fuel handling system be designed "with appropriate containment, confinement, and filtering systems," and "to prevent significant reduction in fuel storage coolant inventory under accident conditions."

The initial core will be loaded into the reactor under dry conditions and will consist of only new, unirradiated fuel. Therefore, all fuel handling accidents should have a minimal effect and should not result in significant releases of radioactivity. New fuel does not produce any significant amounts of heat and, therefore, does not require cooling. Since there should be no need for any cooling, and since significant radiological consequences are not associated with fuel handling accidents involving new fuel, the staff concludes that fueling the initial core under dry loading conditions is acceptable. Hence, there is no need for the fuel bundles to be handled under water, or for water to be in the spent fuel pool. With no water in the spent fuel pool, there is no justification for requiring the fuel handling system to be preoperationally tested under water for the initial core loading.

On the basis of the above, the applicant's request tc defer the preoperational testing of the fuel handling system's capability to transfer fuel under water until after fuel loading, but before exceeding 5% of rated reactor power or before removal of the reactor pressure vessel head after initial criticality, is acceptable and an exemption from the requirements of GDC 61 will be granted.

2.8 In-Place Filter Testing of the Control Room Heating, Ventilation, and Air Conditioning (HVAC) System

The applicant requests deferral of final in-place filter testing of the control room HVAC system until before initial criticality. GDC 19 is applicable in the case of the control room HVAC system. Since before initial criticality there are no significant fission and/or activation products in either the primary coolant system or the ventilation air, the applicant's request is acceptable and an exemption from the requirements of GDC 19 will be granted.

2.9 Heating, Ventilation, and Air Conditioning (HVAC) System

(a) The applicant requests deferral of preoperational phase testing of the auxiliary building HVAC system and the drywell purge system until after fuel load but before reactor heatup. Also requested is deferral until before

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reactor heatup of pressure boundary testing for the auxiliary building and in-place filter testing for the drywell purge system. The auxiliary building HVAC system impacts on control of releases of radioactivity and thus GDC 60 is applicable. The drywell purge system pertains to containment atmosphere cleanup and control of releases of radioactivity and, therefore, GDC 41 and 60 are applicable. The auxiliary building HVAC system and the drywell purge system are not required to be operable before the plant is placed in the operating mode since before reactor heatup there should not be appreciable quantities of airborne radioactivity in these areas. The applicant has committed to complete the testing of these two systems before placing the plant in the operating mode. Thus, the applicant's request is acceptable when releases of radioactivity are limited after initial criticality before reactor heatup and an exemption from the GDC requirements relative to the auxiliary building HVAC system and the drywell purge system will be granted.

(b) The applicant has proposed deferring the final air balancing for the auxiliary building HVAC system, drywell cooling system, drywell purge system, containment building HVAC system, turbine building HVAC system, and the radwaste building HVAC system until after fuel load. Before fuel loading, the applicant will complete the preliminary air balancing for these HVAC systems. Final balancing of these HVAC systems is not possible until system heat loads are developed during preoperational phase testing. As such, these systems will be essentially functional to fulfill anticipated needs before completion of these final air balancing tests. The applicant has committed to complete the final balancing before plant heatup. The staff finds that this is a deferral typical of a number of items that cannot be completed until certain operational functions have been activated. The deferral is, therefore, acceptable.

(c) The applicant requests deferral of pressure boundary testing of the radwaste, turbine, fuel, and containment buildings until after fuel load but before reactor heatup. Deferral of in-place high-efficiency particulate air (HEPA) filter testing for the radwaste building until before reactor heatup is also requested. GDC 60, "Control of Releases of Radioactive Materials to the Environment," and GDC 63, "Monitoring Fuel and Waste Storage," are applicable to the radwaste building. GDC 64, "Monitoring Radioactivity Releases" and GDC 57, "Closed System Isolation Valves," are applicable to the containment building. GDC 61, "Fuel Storage and Handling and Radioactivity Control," and GDC 63, "Monitoring Fuel and Waste Storage," are applicable to the fuel building. There are no GDC requirements for the turbine building. Before reactor heatup, there should not be appreciable quantities of airborne radioactivity in these buildings if the reactor pressure vessel head has not been removed after initial criticality; therefore, the applicant's request is acceptable and an exemption from the GDC requirements will be granted.

2.10 Solid Radwaste System

The applicant also requested deferral of the solid radwaste system preoperational test beyond the fuel load date, but before the primary system heatup. GDC 60 requires a plant to have a solid radwaste system.

The staff accepted in this supplement to the SER the use of the Associated Technology Incorporated (ATI) transportable system instead of the permanently installed solid radwaste system at Clinton. The ATI system satisfies GDC 60. Therefore, the staff finds the applicant's request for deferral of the preoperational test of the permanently installed solid radwaste system to be acceptable and no exemption is required.

3.0 CONCLUSION

On the basis of the foregoing review of the requested deferral items, the deferral requests are not considered to pose any risk to the property or the health and safety of the public and are, therefore, acceptable as modified by the staff. Although these deferral items do affect the applications of some general design criteria, there are mitigating measures to compensate for the deviations created in the interim until the deferrals are completed. The deferral items discussed above, except where noted, will appear as exemptions in the license.

One matter remains to be resolved before the staff completes its review of the proposed exemptions: the applicant's demonstration of the capability to satisfactorily control activities associated with these exemptions after the low-power license has been issued. This matter is currently being considered by Region III staff and is scheduled to be resolved before the low-power license is issued. Details of the resolution will be reported in a Region III inspection report.

On the basis of telephone discussions with the applicant on the traversing incore probe (TIP) system with respect to workers' radiation protection, the staff understands that TIP operational procedures will include a requirement to contact the Health Physics Department (HPD) before using the system. The HPD will ensure that the TIP room is cleared and will set up health physics safety measures, including those Technical Specification requirements for potentially high radiation areas.

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APPENDIX O

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
RELATING TO THE REVIEW OF THE HUMPHREY CONCERNS
FOR CLINTON POWER STATION, UNIT NO. 1

In a letter dated May 8, 1982, Mr. J. Humphrey, a former General Electric (GE) engineer, notified Mississippi Power and Light Company (MP&L) of certain safety concerns regarding the Grand Gulf Mark III containment design. The staff met with MP&L, GE, and Mr. Humphrey to determine the character of these concerns and to establish an appropriate program for their resolution. A number of other Mark III plant applicants attended the meeting, including representatives of Illinois Power Company (IPC) for Clinton Power Station.

The staff has reviewed the information supplied by the applicant for Clinton. These letters contain the applicant's responses to all the Humphrey concerns. Additional sources of relevant documents reviewed by the staff are listed in the References section at the end of the specific evaluations.

There are 66 individual Humphrey concerns covering 22 major areas [referred to as Action Plans by the Mark III Containment Issues Owners Group (CIOG)]. Brookhaven National Laboratory (BNL) assisted the staff in evaluating several Humphrey concerns. The staff has endorsed the evaluation of those items that were provided by BNL. The body of this appendix contains a description, evaluation, and staff conclusion for each Humphrey concern.

HUMPHREY CONCERNS 1.1, 1.2, 1.4, AND 1.5

1.1 Presence of local encroachments, such as the traversing in-core probe (TIP) platform, the drywell personnel airlock, and the equipment and floor drain sumps may increase the pool swell velocity by as much as 20 percent.

1.2 Local encroachments in the pool may cause the bubble breakthrough height to be higher than expected.

1.4 Piping impact loads may be revised as a result of the higher pool swell velocity.

1.5 Impact loads on hydraulic control unit (HCU) floor may be imparted and the HCU modules may fail, which would prevent successful scram if the bubble breakthrough height is raised appreciably by local encroachments.

Evaluation

The concern is that the presence of encroachments will tend to increase pool velocities and the breakthrough height relative to the unencroached pool, thereby causing increases in a variety of LOCA loads including bulk and froth impact, and drag loads in regions above the initial pool surface. As a result of the 1/10-scale simulations of pool swell conducted by CIOG as reported in References 1.1.1, 1.1.2, and 1.1.3, it has now been established that, for the

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most part, the effect of encroachments is to decrease pool swell velocities relative to an unencroached or clean suppression pool. BNL has reviewed all of this information and has prepared a separate Technical Evaluation Report on its findings (Reference 1.1.4).

For those cases in which pool swell velocities are reduced by the presence of encroachments, this concern is considered to be resolved. For Clinton, however, one instance of pool velocity increase was observed (Reference 1.1.2, Clinton II geometry); this occurred directly adjacent to the containment wall. The excess in velocity was about 17%.

As discussed in Reference 1.1.4, the 1/10-scale tests can be shown to be overly conservative in terms of the way in which the pool swell was driven. This conservatism was quantified in Reference 1.1.4 by comparing the 1/10-scale clean pool tests with the 1/3-area-scale Pressure Suppression Test Facility (PSTF) tests (Reference 1.1.5) interpreted as 1/3-scale geometric simulations by means of Moody's scaling laws. Note that the NRC specification of pool swell velocity is based on these latter tests. The conclusion based on this comparison is that the 1/10-scale tests overpredict peak pool velocity by about 80%. If it is assumed that this same correction applies to the encroached results, the peak measured velocity is found to be well below the peak value (50 fps) used for design-basis loads.

One additional concern that was identified in the Clinton 1/10-scale tests was the impact loading experienced by one of the encroachments that was examined. This ledge, which extended 3 feet from the edge of the personnel and equipment hatch platforms, exceeded the established small-structure criteria for bulk impact loads. The applicant addressed this concern in Reference 1.1.6 by developing an impact design load using the results of the 1/10-scale tests to determine a duration of impact (0.019 sec) and combining this with procedures already approved by the NRC staff for this purpose. The applicant has stated that the loads developed by this method are actually less than those used for the original design of the structure. The staff has examined this proposed load methodology and concludes that it would represent an acceptable design load.

Conclusion

The staff considers these issues closed for Clinton because the 1/10-scale tests have confirmed that encroachment effects on pool swell behavior will not give rise to loading conditions that cannot be accommodated by the existing design basis.

References

1.1.1 Sets of slides provided by CIOG to NRC from the following 1/10-scale tests: (a) Clinton Tests F2R, R05, and F5; (b) Grand Gulf Test E3; (c) Perry Test D2, (d) an unidentified clean pool test (see letter of March 19, 1985, from J. E. Torbeck to R. Pender, cc: J. Kudrick of NRC).

1.1.2 "Comparison of Velocities and Thicknesses of Water Column at Containment Wall for 1/10 Scale Pool Swell Tests," submitted by G. W. Smith of CIOG to H. R. Denton of NRC via letter of May 15, 1985.

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1.1.3 Mintz, S., et al., "Clinton Plant Unique Encroachments Final Test Report," General Electric Report MDE-36-0285, Attachment to IPC letter No. U-600006 dated April 29, 1985, from F. A. Spangenberg, (IPC) to A. Schwencer (NRC).

1.1.4 Sonin, A., and Economos, C., "Resolution of the Humphrey Issues Relating to Pool Swell in Mark III Plants," BNL Technical Evaluation Report, February 1985.

1.1.5 Ernst, R. J., et al., "Mark III Confirmatory Test Program One-Third Scale Three-Vent Tests (Test Series 5801 through 5804)," General Electric Report No. NEDM-13407P, May 1975.

1.1.6 IPC letter No. U-600020 dated May 16, 1985, from F. A. Spangenberg (IPC) to W. R. Butler (NRC).

HUMPHREY CONCERN 1.3

Additional submerged structure loads may be applied to submerged structures near local encroachments.

Evaluation

The loads addressed under this item fall into two categories: (1) loads on submerged boundaries (drywell wall, basemat, containment wall) and (2) loads on submerged structures proper, such as pipes and beams.

A two-dimensional SOLAV01 simulation was employed to determine the effect of Clinton encroachments on these loads (Reference 1.3.1). An increase in the containment wall load was predicted which is within the design load specification. For submerged structure loads, margins were obtained for all but one or two structures (References 1.3.1 and 1.3.2). However, all structures are stated to be capable of accommodating the increased loads.

Conclusion

The staff considers this concern resolved because the stated margin between design and the loads was estimated with a conservative (two-dimensional) simulation of the encroachment effect.

References

1.3.1 IPC letter No. U-0714 dated May 25, 1984, from D. I. Herborn (IPC) to A. Schwencer (NRC).

1.3.2 Mark III Containment Issues Review Panel, "Assessment of Humphrey Concerns," CREARE R&D, Inc., Technical Memorandum TM-928, July 1984.

HUMPHREY CONCERN 1.6

Local encroachments on the steam tunnel may cause the pool swell froth to move horizontally and apply lateral loads to the gratings around the HCU floor.

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Evaluation

The applicant has performed a potential flow analysis of the flow field through the HCU floor (Reference 1.6.1). This analysis assumed steady flow; i.e., the liquid droplets had velocities equal to air and all of the froth was allowed to pass through the openings in the HCU floor. The resulting horizontal pressure differentials were found to be 0.45 psi on the beams and 0.26 psi on the gratings. Floor and grating loads are stated to be well within design limits.

The staff concurs with the applicant's claim that the potential flow analysis is conservative. In fact, independent calculations conducted by the NRC indicate that more than 90% of the froth will continue in the vertical direction, hit the HCU floor, and lose all its velocity. As the froth begins to fall back toward the pool, the horizontal component of the flowing air will accelerate the froth to some extent, but steady-state conditions are not expected to be attained. Considering that the additional stresses are modest even with a conservative flow analysis, the staff concludes that additional effort does not need to be expended on this issue.

Conclusion

The staff considers this issue closed.

Reference

1.6.1 IPC letter No. P23-83(05-31) dated May 31, 1983, G. E. Wuller (IPC) to A. Schwencer (NRC).

HUMPHREY CONCERN 1.7

GE suggests that at least 1,500 ft^2 of open area should be maintained in the HCU floor. In order to avoid excessive pressure differentials, at least 1,500 ft^2 of open area should be maintained at each containment elevation.

Evaluation

The applicant has indicated that the Clinton design provides open areas on all floors above the HCU floor greater than the open area at the HCU floor (Reference 1.7.1). The latter, at 1,824 square feet, is substantially greater than the required minimum.

Conclusion

On the basis of the above response, the staff considers this issue closed.

Reference

1.7.1 IPC letter No. U-0562 dated November 23, 1982, from G. E. Wuller (IPC) to C. O. Thomas (NRC).

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HUMPHREY CONCERN 2.1

The annular regions between the safety relief valve lines and the drywell wall penetration sleeves may produce condensation oscillation (CO) frequencies near the drywell and containment wall structural resonance frequencies.

Evaluation

As stated above, the concern is that additional and unaccounted for suppression pool boundary loads may be produced by steam condensation at the exit of the sleeve annulus. However, the scope of this concern is expanded considerably by Humphrey in Reference 2.1.1. There it is speculated that, because of resonant coupling between the sleeve annulus CO and the sleeve annulus acoustics, the pressure loads at higher frequencies could be amplified.

The applicant first addressed this concern using the generic approach described in Reference 2.1.2. This methodology derives sleeve annulus CO loads by conservatively scaling down the main vent CO load data base. The potential for resonant amplification of these loads was not addressed.

The use of the main vent CO data base for development of sleeve annulus loads cannot be rigorously defended because of substantial differences in geometry. However, on the basis of the relative size of the steam/water interface that would exist at the sleeve annulus, it could be judged that any additional non-resonant loads that may occur will be second order relative to main vent loads. This judgment applies to both CO and chugging loads.

The added sleeve CO loads that were first proposed are substantial. For example, the peak-to-peak pressure amplitude (PPA) was about 20% of that used in the main vent load definition. They are also applied uniformly in the circumferential direction which represents a sizable conservatism. This is because there are roughly twice as many main vents as drywell penetration sleeves. These modifications are clearly more than second order. Thus, provided it could have been demonstrated that resonant amplification does not occur, the CO loads which were specified would have been considered adequate.

In an attempt to demonstrate the absence of such a coupling, the applicant cited results from General Electric's 4T CO tests (Reference 2.1.3). A review of this material indicated that the contrary was the case. That is, the data implied that the type of resonant coupling suggested by Humphrey was not only possible, but apparently had actually occurred. In fact, it can be inferred from these data that resonance causes about a two-fold increase in the basic CO loads.

As a result of this finding, the applicant proposed a completely new methodology for the CO boundary loads (Reference 2.1.4). This methodology has been developed by General Electric utilizing the Mark I Full-Scale Test Facility (FSTF) data base (Reference 2.1.5). This new design loading results in a substantial increase in the pressure loading at the higher end of the frequency spectrum (20-50 Hz). For example, in terms of an amplified response spectrum (ARS), the load intensity is about double the one first proposed.

These new loads are shown to be bounded by other design-basis loads. For example, on the drywell wall the new sleeve CO load when added to the main vent CO

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is bounded by the chugging load specification. On the containment wall, the bound is provided, with considerable margin, by the pool swell boundary load. The applicability of the FSTF data to the sleeve annulus loads involves considerable uncertainty because of the great disparity in geometries between the two situations. This applies not only for the steam-water interface at the respective pipe exits but, more importantly, for the acoustic path through which the mechanism that drives the CO phenomenon is transmitted. In fact, it is not completely apparent that for the FSTF case the system has actually achieved a condition of resonant coupling. This is because of the complexity of the FSTF vent system (the eight downcomers are connected to a vent header, which in turn is connected to a main vent which then connects to a simulated drywell). Because of this complexity, it is difficult to ascertain the effective relevant vent system natural frequency with sufficient precision.

Despite the uncertainties cited above, several factors may be cited that compensate for any possible inadequacy. First, there is the qualitative evidence from the 4T CO tests (Reference 2.1.3) that, even when resonant coupling clearly occurs, the load amplification is limited to less than a two-fold factor. Also, the generally conservative application of the available results provides increased confidence in the adequacy of the load method. For example, the pressure results observed on 24-inch-diameter downcomers are taken over directly and applied to the much smaller, 14-inch-diameter, safety/relief valve discharge line (SRVDL) sleeves. Also, in developing the loads on the suppression pool boundaries, the effective source (steam bubble) radius was taken equal to that of the sleeve without taking into account the actual presence of the SRVDL itself. As shown in a recent submittal by the applicant (Reference 2.1.6), this results in a margin of more than 30% in the loads that were developed. The staff concludes the margin would be even greater if the steam bubble were modeled more realistically (Reference 2.1.2). Additional conservatism stems from the use of conventional acoustics for determination of pressure attenuation from the source to the pool boundaries. Dissipative mechanisms that are present in the suppression pool and neglected in the analysis, would further reduce the loads.

BNL has not received a description of the chugging loads, even though this information exists (Reference 2.1.7) and has been assessed by the Mark III Containment Issues Review Panel (Reference 2.1.8).

Industry found that the proposed loads were only about 6% of main vent chugging and are easily bounded by design. The staff is satisfied that this is the case. Note that resonance effects are not expected to play any role in or influence the chugging phenomenon associated with the sleeve's annulus.

Conclusion

The staff considers this concern satisfactorily resolved because the conservatively estimated loads have been demonstrated to be bounded by other design loads.

References

2.1.1 Humphrey Engineering, Inc., letter dated June 17, 1982, from J. M. Humphrey (HEI) to A. Schwencer (NRC).

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2.1.2 IPC letter No. U-0714 dated May 25, 1984, from D. I. Herborn (IPC) to A. Schwencer (NRC).

2.1.3 Bird, P. F., et al., "4T Condensation Oscillation Test Program Final Test Report," General Electric Report NEDE-24811-P, May 1980.

2.1.4 IPC letter No. U-600319 dated November 25, 1985, from F. A. Spangenberg (IPC) to W. R. Butler (NRC).

2.1.5 Fitzsimmons, G. W., et al., "Mark I Containment Program - Full-Scale Test Program Final Report," General Electric Report NEDE-24539-P, April 1979.

2.1.6 IPC letter No. U-600588 dated May 30, 1986, from F. A. Spangenberg (IPC) to W. R. Butler (NRC).

2.1.7 Enercon letter No. RWE-OG-060 dated May 25, 1983, from R. W. Evans (Enercon) to B. R. Patel (CREARE R&D).

2.1.8 Mark III Containment Issues Review Panel, "Assessment of Humphrey Concerns," CREARE R&D, Inc., Technical Memorandum TM-928, July 1984.

HUMPHREY CONCERNS 2.2 and 2.3

2.2 The potential condensation oscillation and chugging loads produced through the annular area between the SRVDL and sleeve may apply unaccounted for loads to the SRVDL. Since the SRVDL is unsupported from the quencher to the inside of the drywell wall, this may result in failure of the line.

2.3 The potential condensation oscillation and chugging loads produced through the annular area between the SRVDL and sleeve may apply unaccounted for loads to the penetration sleeve. The loads may also be at or near the natural frequency of the sleeve.

Evaluation

The concern is that the steam condensation process (CO + chugging) at the sleeve annulus exit will give rise to loads on the SRVDL, and SRVDL sleeve analogous to the lateral loads experienced by Mark I and Mark II downcomers during postulated LOCA blowdowns, and that these structures have not been designed to accommodate them. The applicant's specification for chugging loads is given in Reference 2.2.1 with additional clarification provided in Reference 2.2.2. The load has a half-sinusoidal time dependence with a duration of 3 mseconds and a peak amplitude of 28 kips. It is stated that this load derives from the Mark II load methodology of Reference 2.2.3 as modified by the NRC staff's acceptance criteria (Reference 2.2.4). The load is developed by scaling down the peak amplitude to the outside diameter of the SRVDL sleeve and accounting for the fact that there are fewer chug sources created by flow through the SRVDL sleeve annulus than exist during design-basis-accident (DBA) blowdowns through the Mark II pressure suppression system (i.e., 16 SRVs for Clinton vs. about 100 downcomers in a typical Mark II plant). Scaling down for pipe diameter is accomplished by assuming a 1.7 power dependence of the peak load amplitude on diameter. Load reduction for fewer chugging sources utilizes the

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staff-approved statistical representation for these loads (Reference 2.2.4). The region of application of the load is also scaled down using a first power dependence on diameter (Reference 2.2.2).

The applicability of the Mark II results for the present application is somewhat uncertain because of the substantial geometric differences (straight down vs. inclined pipe and annular vs. circular cross-section). Nevertheless, the staff finds the approach reasonable and, in general, conservative. The use of a 1.7 power dependence of peak amplitude on pipe diameter is somewhat less conservative than the staff would have preferred since the available data (Reference 2.2.5) exhibit exponent values that range from 0.7 to 1.7. On the other hand, no credit is taken for the presence of the SRVDL in the steam bubble. This provides a substantial conservatism that the staff judges more than compensates for any possible nonconservatism in selecting this exponent.

No CO laterial loads are specified by the applicant. In Reference 2.2.2 it is argued that since the suppression pool end of the SRVDL sleeve is truncated perpendicular to the discharge line axis, the potential for asymmetric dynamic pressure loads arising at that end is precluded. It is also argued (Reference 2.2.6) that at the drywell end of the sleeve where the truncation is at 45° to the pipe axis, a constant pressure condition prevails during the CO phase of the DBA blowdown. This would tend to suppress the development of unbalanced pressure loads across the SRVDL because only a very small section of the longer end of the pipe would experience the pressure reversal resulting from reflection off the annulus entrance. The staff believes that these arguments have sufficient merit to justify the absence of any explicit CO lateral load specification on the SRVDL and SRVDL sleeve during postulated LOCA conditions.

Conclusion

The staff considers this concern resolved because of the specification of a conservative chugging load for the SRVDL and SRVDL sleeve, and because the Clinton configuration for these structures does not permit development of any significant unbalanced pressure loading during the CO phase of the LOCA blowdown.

References

2.2.1 IPC letter No. U-0714 dated May 25, 1984, from D. I. Herborn (IPC) to A. Schwencer (NRC).

2.2.2 IPC letter No. U-600319 dated November 25, 1985, from F. A. Spangenberg (IPC) to W. R. Butler (NRC).

2.2.3 Davis, W. M., "Mark II Main Vent Lateral Loads," GE Report NEDE-23806-P, October 1978.

2.2.4 Anderson, C., "Mark II Containment Program Load Evaluation and Acceptance Criteria," NRC NUREG-0808.

2.2.5 General Electric letter MFN-050-80 dated February 29, 1980, from R. H. Buchholz (GE) to C. J. Anderson (NRC).

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2.2.6 Informal telephone conference between BNL/NRC/IPC/GE/S&L, December 3, 1985.

HUMPHREY CONCERNS 3.1 and 3.3

3.1 The design of the STRIDE (STandard Reactor Island DEsign) did not consider vent clearing, condensation oscillation, and chugging loads which might be produced by the actuation of the RHR heat exchanger relief valves.

3.3 Discharge from the RHR relief valves may produce bubble discharge or other submerged structure loads on equipment in the suppression pool.

Evaluation

The concern is that, besides the main safety/relief valves (MSRVs), the residual heat removal (RHR) relief valves can also discharge fluids into the suppression pool during RHR operation in the steam condensing mode (SCM). As a result, loads could be produced analogous to those associated with MSRV discharges and/or LOCA blowdowns through downcomers. These loads have not been accounted for in plant design.

The applicant states in Reference 3.1.1 that water and air clearing loads were developed by conservative application of conventional methods (i.e., the main steam SRV load methodology). The applied loads are those that correspond to subsequent actuation at maximum reflood elevation; these are found to be "worst case" loads. The resulting containment boundary loads were assessed and found to be within design. Water clearing jets are found not to impinge on any structures in the Clinton suppression pool. Air clearing loads on submerged structures exceeded MSRV design loads in a few cases but all structures were found capable of accommodating these increases in applied loads.

For CO and chugging loads on the pool boundaries, the applicant utilizes the generic methods employed by all the Mark III utilities (Reference 3.1.2). No detailed description of the methodology is supplied by the applicant, but the general features can be discerned from the information supplied in References 3.1.3 and 3.1.4. Generally speaking, the method derives from a conservative application of the Mark II CO and chugging methodologies. The specific application is to the Grand Gulf Nuclear Station (Grand Gulf) RHR heat exchanger relief valve discharge line (RHRHXRVDL). Source terms are developed from selected chugs and CO pressure signatures from the Mark II data base. These are used to generate pressure loads on the Grand Gulf pool boundaries. They are shown to be bounded by the design main steam SRV loads by a wide margin.

The conservatism in this load specification stems primarily from the use of the selected source strength directly without any reduction to account for the difference in pipe diameter between the RHRHXRVDL (12 inches in Clinton), and that from which the data base derives (24 inches in the test facility).

The adequacy of the CO load also needs to be judged in the context of potential unstable steam condensation; i.e., elevated suppression pool temperature. The staff's evaluation of this aspect is presented under Humphrey Concern 3.6.

A detailed description of lateral loads on the discharge line due to chugging is provided in Reference 3.1.5. The load is time dependent (half-sinusoid)

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with a peak amplitude of 32.5 kips and 3 msecond duration. This load derives from the Mark II load methodology of Reference 3.1.6 as modified by the NRC staff's acceptance criteria (Reference 3.1.7) to account for the stochastic nature of the chugging phenomenon. This results in a peak design load amplitude that varies according to the number of chugs that would be expected during a particular accident scenario, and the desired nonexceedance probability.

The peak amplitude selected by the applicant takes into account only the difference in diameter between the RHR discharge line (12 inches) and the standard Mark II downcomer (24 inches). This is accounted for by assuming that the peak amplitude scales with pipe diameter to the first power. It does not, for example, adjust the load for reduced submergence, which is also known to attenuate such loads. In particular, no modification for nonexceedance probability is employed so that the selected peak amplitude is to be associated with that used to derive the Mark II downcomer load. This is a very low probability value (10^{-5}) and implies that many hours of chugging could occur before a serious exceedance of pipe structural capability would be expected.

Conclusion

The staff judges that this issue has been satisfactorily resolved. This judgment is based on the conservative nature of the loads used for evaluation and the stated margins exhibited in existing structure capability.

References

3.1.1 IPC letter No. U-714 dated May 25, 1984, from D. I. Herborn (IPC) to A. Schwencer (NRC).

3.1.2 Mark III Containment Issues Review Panel, "Assessment of Humphrey Concerns," CREARE R&D, Inc., Technical Memorandum TM-928, July 1984.

3.1.3 Meeting handouts from NRC/Mark III/GE meeting of May 19-20, 1983.

3.1.4 Ashley, G. K., and Leong, T. S., "Assessment of RHR Steam Discharge CO in Mark III Containments," Bechtel Report, March 1984.

3.1.5 IPC letter No. U-600319 dated November 25, 1985, from F. A. Spangenberg (IPC) to W. R. Butler (NRC).

3.1.6 Davis, W. M., "Mark II Main Vent Lateral Loads," GE Report NEDE-23806-P, October 1978.

3.1.7 Anderson, C., "Mark II Containment Program Load Evaluation and Acceptance Criteria," NRC NUREG-0808.

HUMPHREY CONCERN 3.2

The STRIDE design provided only 9 inches of submergence above the RHR heat exchanger relief valve discharge lines at low suppression pool levels.

Evaluation

The concern is that because of the relatively small submergence involved, steam condensation may not be complete, leading to steam bypass and failure of the pressure suppression system.

The applicant has addressed this concern using the generic approach common to all plants (Reference 3.2.1). The approach cites the full-scale data from the Humboldt Bay tests where it is shown that, over a wide range of steam flux rate, condensation was complete (i.e., no steam bypass and containment pressurization), even with a clearance of 2 feet between the vertical vent pipe exit and pool surface.

The applicant states (Reference 3.2.2) that the minimum submergence of the discharge line will be about 2 inches. This differs considerably from the 4-foot minimum suggested in Reference 3.2.3. Notwithstanding this discrepancy, in the staff's judgment, submergence, together with the degree of subcooling that would be expected during normal steam discharges through these lines (see discussion of Humphrey Concern 3.6), will preclude any potential for steam bypass.

Conclusion

The staff considers this issue satisfactorily resolved for Clinton based on the discussion above.

References

3.2.1 MP&L letter No. AECM-82/353 dated August 19, 1982, from L. F. Dale (MP&L) to H. R. Denton (NRC).

3.2.2 IPC letter No. U-0596 dated February 4, 1983, from G. E. Wuller (IPC) to A. Schwencer (NRC).

3.2.3 Mark III Containment Issues Review Panel, "Assessment of Humphrey Concerns," CREARE R&D, Inc., Technical Memorandum TM-928, July 1984.

HUMPHREY CONCERN 3.4

The RHR heat exchanger relief valve discharge lines are provided with vacuum breakers to prevent negative pressure in the lines when discharging steam is condensed in the pool. If the valves experience repeated actuation, the vacuum breaker sizing may not be adequate to prevent drawing slugs of water back through the discharge piping. These slugs of water may apply impact loads to the relief valve or be discharged back into the pool at the next relief valve actuation, and apply impact loads to submerged structures.

Evaluation

The concern is that the various steam discharge lines may not have been equipped with properly sized vacuum breakers. This is a credible concern in view of the historical development of the same issue for the MSRVs. Because the potential for subsequent actuations was not fully appreciated in the early stages, the MSRV discharge lines were originally equipped with undersized

vacuum breakers. When very high reflood elevations were encountered during tests with subsequent actuation, it became evident that this was so and much larger vacuum breakers were installed (from 1-inch diameter to as much as 10-inch diameter, or two 6-inch diameter).

The applicant indicates (Reference 3.4.1) that the Clinton discharge lines are equipped with 2-inch vacuum breakers, a size considered marginally adequate for a 12-inch-diameter discharge line. The applicant's reflood analysis, performed with a standard GE computer model, reflects this. The results show a reflood elevation of about 13 feet, which is considerable, but still well below any crucial element of the system (the vacuum breakers are lowest and are located about 2½ feet above maximum reflood). Water clearing loads were developed using this maximum reflood and all piping systems found capable of accommodating these loads.

Conclusion

The staff considers this issue adequately addressed by the applicant and, therefore, closed.

Reference

3.4.1 IPC letter No. U-0714 dated May 25, 1984, from D. I. Herborn (IPC) to A. Schwencer (NRC).

HUMPHREY CONCERN 3.5

The RHR relief valves must be capable of correctly functioning following an upper pool dump, which may increase the suppression pool level as much as 5 feet, creating higher back pressures on the relief valves.

Evaluation

The purpose of the RHR relief valve, on each RHR train, is to prevent the overpressurization of the RHR heat exchanger should the control valve fail during operation of the RHR system in the steam condensing mode. Upper pool dump is a design-basis-accident (DBA) mitigating device that will not be used in conjunction with the operation of the RHR system in the steam condensing mode, which is not utilized to mitigate DBA events. Therefore, multiple failures of safety-grade equipment would have to occur before the scenario postulated by Humphrey could occur. The staff does not consider this scenario within design bases.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 3.6

If the RHR heat exchanger relief valves discharge steam to the upper levels of the suppression pool following a design-basis accident, they will significantly aggravate suppression pool temperature stratification.

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Evaluation

Although the concern suggests that these discharges will occur following a DBA, the applicant has indicated (Reference 3.6.1) that during post-LOCA conditions the "RHR logic precludes the initiation of the steam condensing mode (SCM)." Under these circumstances, steam discharges via the RHR heat exchanger relief valves cannot occur. On the other hand, continuous steaming for an extended period under normal conditions is possible and could not only result in excessive containment pressurization via vertical thermal stratification, but introduces the potential for unstable steam condensation leading to excessive dynamic loading on the pool boundaries.

The applicant's response to this issue was given in Reference 3.6.2, and is similar to the generic approach which was provided for Grand Gulf (Reference 3.6.3). A demonstrably conservative model of thermal deposition, stratification, and pool mixing was developed and applied using Grand Gulf plant parameters. On the basis of this model, it was shown in Reference 3.6.4 that even after steaming at the very high flow rate assumed in the analysis for 20 minutes, the difference between average pool surface temperature (131°F) and bulk temperature (107°F) was only about 24°F. The staff notes also that the peak temperatures reported are just barely approaching levels that might imply unstable steam condensation loads; e.g., about 130°F for a straight-down pipe. Accordingly, the staff concludes that this scenario could safely proceed for as much as 20 minutes without the need for any mitigating action. The applicant takes the position that because operation in the SCM is so operator intensive, detection of a failure and termination of the steam flow could be accomplished within two minutes. This appears to be somewhat optimistic, but the staff is satisfied that sufficient time is available to institute a number of actions which would effectively mitigate any adverse effects of this postulated failure.

Conclusion

The issue raised by this concern is considered to be satisfactorily resolved for Clinton based on the conclusion that operation of the RHR in a steam condensing mode will be prevented by either design or by operator action.

References

3.6.1 IPC letter No. U-600319 dated November 25, 1985, from F. A. Spangenberg (IPC) to W. R. Butler (NRC).

3.6.2 IPC letter No. U-596 dated February 4, 1983, from G. E. Wuller (IPC) to A. Schwencer (NRC).

3.6.3 MP&L letter No. AECM-82/574 dated December 3, 1983, from L. F. Dale (MP&L) to H. R. Denton (NRC).

3.6.4 Meeting handout, "Response to Question 9.2," NRC/Mark III/GE meeting, May 19-20, 1983.

HUMPHREY CONCERN 3.7

The concerns related to the RHR heat exchanger relief valve discharge lines should also be addressed for all other relief lines that exhaust into the pool.

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Evaluation

The reactor core isolation cooling (RCIC) turbine exhaust is the only other line, besides the MSRV and RHR relief discharge line, that discharges steam into the suppression pool. The RCIC turbine exhaust line is equipped with vacuum breakers and a sparger device to eliminate steam discharge problems which were experienced on early Mark I plants. The applicant asserted that operating plants with the RCIC turbine exhaust line configuration, similar to the Clinton design, have not experienced system failures caused by steam condensing loads.

The loads resulting from the RCIC turbine exhaust steam dischargers are judged by the staff to be bounded by the RHR-related loads. This conclusion is based on the RCIC turbine line that uses a load mitigator (sparger), whereas the RHR relief line does not have this component in its design. The RCIC turbine exhaust steam flow is less than the flow rate of the RHR relief line. In addition, the slow opening characteristics of the RCIC inlet valve also reduces steam discharge loads.

Conclusion

The staff considers this issue closed.

Reference

3.7.1 IPC letter NO. U-600319 dated November 25, 1985, from F. A. Spangenberg (IPC) to W. R. Butler (NRC).

HUMPHREY CONCERN 4.1

The present containment response analyses for drywell break accidents assume that the ECCS systems transfer a significant quantity of water from the suppression pool to the lower regions of the drywell through the break. This results in a pool in the drywell which is essentially isolated from the suppression pool at a temperature of approximately 135°F. The containment response analysis assumes that the drywell pool is thoroughly mixed with the suppression pool. If the inventory in the drywell is assumed to be isolated, and the remainder of the heat is discharged to the suppression pool, an increase in bulk pool temperature of 10°F may occur.

Evaluation

Analysis was performed for the Grand Gulf Nuclear Station, and was shown to be applicable to Clinton, assuming the drywell pool is completely isolated at a temperature of 135°F. The bulk pool temperature increase due to this assumption was 10°F. This increase is less than the 20°F margin in peak bulk pool temperature shown by CIOG in response to Humphrey Concern 4.4.

CIOG performed an additional analysis that shows Humphrey's assumption about the initial drywell pool temperature is incorrect. If one assumes that the drywell pool is formed during the initial stages of the transient as postulated by Humphrey, the water in the drywell pool will be a combination of steam condensation from the drywell structures, emergency core cooling system (ECCS),

water spillage, and the unflashed portion of the reactor vessel blowdown. The temperature of this mixture is calculated to be 230°F which, if isolated from the suppression pool, will result in lower suppression pool bulk temperatures.

The applicant has shown that the drywell pool temperature, when isolated early as postulated by Humphrey, is higher than the peak suppression pool temperature and, therefore, will result in lower suppression pool temperatures, notwithstanding this effect, the increase in the peak bulk suppression pool temperature of 10°F, when the drywell pool is assumed to be isolated at 135°F (which has been shown to be unrealistic), is within the identified pool temperature margins discussed under Humphrey Concern 4.4.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERNS 4.2 and 9.1

4.2 The existence of the drywell pool is predicated upon continuous operation of the ECCS. The current Emergency Procedure Guidelines (EPGs) require the operators to throttle ECCS operation to maintain vessel level below level 8. Consequently, the drywell pool may never be formed.

9.1 The current FSAR analysis is based upon continuous injection of relatively cool ECCS water into the drywell through a broken pipe following a design basis accident. The EPGs direct the operator to throttle ECCS operation to maintain reactor vessel level at about level 8. Thus, instead of releasing relatively cool ECCS water, the break will be releasing saturated steam, which might produce higher containment pressurizations than currently anticipated. Therefore, the drywell air which would have been drawn back into the drywell will remain in the containment, and higher pressure will result in both the containment and the drywell.

Evaluation

A conservative end-point analysis was performed for Grand Gulf (MP&L letter dated October 22, 1982), and shown to be applicable to Clinton, to determine the peak containment pressure assuming no redistribution of air between the drywell and containment (as postulated by Humphrey in Concern 9.1), and the containment atmosphere and suppression pool temperatures to be 181°F. Neglecting the temperature differences that would be present between the suppression pool and containment atmosphere is quite conservative. The resulting peak containment pressure was 12.5 psig, which is below the design limit of 15 psig.

An analysis was performed (MP&L letter dated October 22, 1982) assuming a constant vessel water level, initial upper pool temperature of 95°F, standard FSAR values for design-basis-accident (DBA) analysis, and with all break release going directly to the suppression pool to evaluate the effect of no drywell pool being formed on the suppression pool temperature transient, and thus, the containment pressure/temperature transient. The peak pool temperature resulting from this analysis was 165°F, well below the 181°F used in the bounding containment pressure analysis discussed above.

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The assumption of no formation of the drywell pool and no air return to the drywell does not result in higher than design containment pressure results for Mark III plants, even with very conservative assumptions regarding heat transfer processes.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 4.3

All Mark III analyses presently assume a perfectly mixed uniform suppression pool. These analyses assume that the temperature of the suction to the RHR heat exchangers is the same as the bulk pool temperature. In actuality, the temperature in the lower part of the pool where the suction is located will be as much as 7½°F cooler than the bulk pool temperature. Thus, the heat transfer through the RHR heat exchanger will be less than expected.

Evaluation

To complete the statement of this concern, the following should be added: "and containment pressure and temperature greater than expected."

Humphrey's basis for expecting a temperature difference of up to 7½°F is unclear. The staff agrees that in the event of a postulated LOCA, the reality will be a thermally stratified pool. However, to decide what the difference between bulk and RHR suction temperature is requires an estimate of the degree of vertical stratification that will occur, together with knowledge of RHR suction elevation.

The first of these requirements was established to the NRC staff's satisfaction during its evaluation of the GESSAR II containment loads (Reference 4.3.1). After a lengthy and detailed review process by the various interested parties (Reference 4.3.2), the worst case vertical temperature profile proposed by the General Electric Company for design (Fig. 3BI-3 of Reference 4.3.3) was judged acceptable. The basis for this judgment is given in Reference 4.3.1. It implies that the profile is applicable only for a standard top vent submergence (7.5 feet).

In responding to Humphrey Concerns 4.7 and 4.10 (see below), the applicant indicates that the Clinton RHR suction is located at an elevation 8 feet 0 inch above the basemat. Comparison with the temperature profile referred to above implies that the RHR suction temperature is greater than bulk temperature. Accordingly, this Humphrey concern is not relevant to Clinton.

Conclusion

The staff considers this issue satisfactorily resolved for Clinton.

References

4.3.1 "Mark III LOCA-Related Hydrodynamic Load Definition," NUREG-0978, August 1984.

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4.3.2 Transcript of the ACRS Subcommittee on Fluid Hydraulic Dynamic Effects Meeting of September 24-25, 1981.

4.3.3 General Electric Co., 22A707, "General Electric Standard Safety Analysis Report" (GESSAR II), Appendix 3B through Amendment 1, February 25, 1982.

HUMPHREY CONCERNS 4.4 and 7.1

4.4 The long-term analysis of containment pressure/temperature response assumes that the wetwell airspace is in thermal equilibrium with the suppression pool water at all times. The calculated bulk pool temperature is used to determine the airspace temperature. If pool thermal stratification were considered, the surface temperature, which is in direct contact with the airspace, would be higher. Therefore, the airspace temperature (and pressure) would be higher.

7.1 The containment is assumed to be in thermal equilibrium with a perfectly mixed, uniform temperature suppression pool. As noted under Topic 4.4, the surface temperature of the pool will be higher than the bulk pool temperature. This may produce higher than expected containment temperatures and pressures.

Evaluation

The concern is similar to that associated with concern 4.3 above except that here the issue is the difference between pool surface temperature and bulk temperature. On the basis of the GESSAR II temperature profile referred to previously, this difference is 8°F, in rough agreement with the 7½°F difference cited by Humphrey in Concern 4.3. Apparently, this was the ΔT he was referring to and it was mistakenly cited in connection with the bulk-to-RHR suction temperature difference.

The applicant's response to this concern is the generic one that was originally provided by MP&L for Grand Gulf (Reference 4.4.1). In this submittal, the issue is quantified by means of existing information and analyses. The results show that the effects of a 7 to 8°F difference between pool surface and bulk temperature would imply an increase in peak containment pressure and temperature of only 0.1 psi and 3°F, respectively. These modest differences are overwhelmed by the existing margins of 5 psi and 19°F that can be demonstrated to exist due to various conservatisms used in conventional containment response analysis.

Conclusion

Essentially, what this evaluation has demonstrated once more is that the use of a mean or bulk pool temperature is an acceptable simplification that facilitates calculation of containment response. The staff considers this issue closed.

Reference

4.4.1 Attachment to MP&L letter No. AECM82/353 dated August 19, 1982, from L. F. Dale (MP&L) to H. R. Denton (NRC).

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HUMPHREY CONCERN 4.5

A number of factors may aggravate suppression pool thermal stratification. The chugging produced through the first row of horizontal vents will not produce any mixing from the suppression pool layers below the vent row. An upper pool dump may contribute to additional suppression pool temperature stratification. The large volume of water from the upper pool further submerges RHR heat exchanger effluent discharge which will decrease mixing of the hotter, upper regions of the pool. Finally, operation of the containment spray eliminates the heat exchanger effluent discharge jet which contributes to mixing.

Evaluation

On the basis of Reference 4.5.1, the staff concludes that the response for Clinton would be identical to that provided via Reference 4.5.2: the generic response which corresponds to Action Plan 14 of the MP&L submittal for Grand Gulf. This Action Plan was to utilize the following "Program for Resolution."

(1) Testing information will be submitted to demonstrate the effectiveness of chugging as a mixing mechanism in the suppression pool.

(2) Analyses will be submitted to demonstrate that the suppression pool does not experience significant stratification during containment spray or following upper pool dump.

The first of these items addresses the concern that chugging does not provide any mixing below the top vent. The test information that was supplied indicates that this is not correct. Measurements obtained from so-called drag disks that had been installed in the PSTF facility indicated that flow reversals occur periodically in both the middle and bottom vents during the chugging phase of the steam blowdown. Although this is a qualitatively useful finding, the attempt to quantify pool turnover time from this information cannot be taken seriously. This is because the drag disk device requires careful calibration under even the best of circumstances (steady, uniform flow). Under the unsteady, highly nonuniform flow conditions that prevail within the vents during chugging, the notion that quantitatively correct values of flow velocities can be obtained using this procedure is not credible. Furthermore, even if one were to accept these quantitative estimates, their applicability for the case involving upper pool dump, which can increase top vent submergence from 7½ to as much as 12 feet, would be highly suspect.

As for the second item, none of the Mark III applicants has provided any information. The Clinton applicant suggested informally that some relevant information could be developed from a reading of the Clinton FSAR. The staff has done this and has determined, among other things, that the Clinton upper pool volume increases the pool depth by only 2 feet, that the upper pool water at the time of dump is 120°F, and that the suppression pool bulk temperature at the time of pool dump is in the range 136°F to 147°F. The staff has also been able to establish that the dump is accomplished by two 24-inch-diameter gravity-fed drain lines that terminate with a vertical orientation about 19 feet above the suppression pool surface. These drain lines are located at azimuth 53° and 325° which places them in close proximity to the RHR suction lines (azimuth 37° and 323°). Finally, the staff has been informed (Reference 4.5.3) that the dump is accomplished over an 8-minute period of time.

If during this time interval no other mass or energy addition to the suppression pool occurs, the combined suppression bulk pool temperature would be reduced by 2 to 3°F. Thermal stratification, of course, would increase to the same extent, but this bounding value can easily be accommodated, in the staff's judgment, by other conservatisms (see discussion for Concern 4.4). The effect of pool dump on thermal stratification is much more difficult to estimate, but as a limiting case the staff can speculate that the upper pool water, because of its downward velocity (10-20 fps) and greater density, preferentially sinks to the bottom and displaces the hotter stratified layers of pool water. Except for the possibility of short circuiting, which the staff judges to be unlikely because of the high elevation of the Clinton RHR suction, this "cold-water-sinks-to-bottom" scenario represents the worst case in terms of the RHR suction temperature differential from bulk pool temperature. That is, by displacing the hotter layers of water upward, the RHR suction temperature is reduced to the maximum degree possible. Figure 4.5.1 demonstrates this effect. Note especially that although the local temperature at the RHR suction elevation decreases, it still remains higher than bulk pool temperature. This represents an important conservatism as was pointed out during evaluation of Humphrey Concern 4.3 above. Thus, upper pool dump also does not impact negatively on the RHR suction to bulk temperature difference in Clinton.

The remaining concerns implied in this concern are also taken into account in the staff evaluation. This is because staff arguments have used the worst-case thermal stratification; i.e., the temperature profile was developed without assuming RHR operation. Thus, any RHR operation, however inefficient, will further improve the situation characterized.

Conclusion

The staff judges that upper pool dump in Clinton will not seriously increase pool thermal stratification. This is because the increase in pool depth is relatively small (only 2 feet), and because the RHR suction in Clinton is located at a high elevation (8 feet above the basemat) relative to the worst-case temperature profile.

References

4.5.1 Mark III Containment Issues Review Panel, "Assessment of Humphrey Concerns," CREARE R&D, Inc., Technical Memorandum TM-928, July 1984.

4.5.2 MP&L letter No. AECM 82/353 dated August 19, 1982, from L. F. Dale (MP&L) to H. R. Denton (NRC).

4.5.3 IPC informal "Response to Request for Information via Phone Call on August 6, 1985," August 1985.

HUMPHREY CONCERN 4.6

The initial suppression pool temperature is assumed to be 95°F, while the maximum expected service water temperature is 90°F for all Grand Gulf accident analyses as noted in FSAR Table 6.2-50. If the service water temperature is consistently higher than expected, as occurred at Kuosheng, the RHR system may be required to operate nearly continuously in order to maintain suppression pool temperature at or below the maximum permissible value.

Evaluation

The Clinton FSAR analysis uses an initial suppression pool temperature of 95°F and a service water temperature of 90°F. The worst-case maximum standby service water temperature is 90°F for Clinton. This temperature is the highest 1-day average water temperature based upon the once-in-50-years worst-case situation. MP&L submitted an analysis for Grand Gulf by letter dated August 19, 1982, which the staff finds to be an adequate representation for Clinton. The following describes the Grand Gulf analysis.

During normal plant operation (excluding test conditions), the only possible mechanism to raise the pool temperature is leakage through the main steam safety relief valves. A simplified suppression pool heatup analysis assuming 20 lb/hr steam leakage from each of the main steam safety/relief valves was performed by MP&L. The results of the analysis show that it takes 10 days for the suppression pool temperature to rise from 90°F to 95°F and 2.3 hours for the RHR system (with 75°F service water temperature) to cool the pool back down to 90°F. Whereas, in the Clinton case it would take longer than 2.3 hours to cool the pool down to about 90°F.

The staff has reviewed the initial conditions, assumptions, and analysis techniques utilized by the applicant with regard to this issue, and concludes that the RHR system is capable of maintaining the suppression pool temperatures below its Technical Specification value with only intermittent usage, even under the most severe normal operating conditions.

Conclusion

The staff considers this issue closed.

Reference

4.6.1 IPC letter No. U-0615 dated March 17, 1983, from G. E. Wuller (IPC) to A. Schwencer (NRC).

HUMPHREY CONCERNS 4.7 AND 4.10

4.7 All analyses completed for the Mark III are generic in nature and do not consider plant-specific interactions of the RHR suppression pool suction and discharge.

4.10 Justify that the current arrangement of the discharge and suction points of the pool cooling system maximizes pool mixing.

Evaluation

The concern is that if the RHR system's geometric arrangement for the suction and return lines is not properly designed, the capability of the system to induce bulk mixing and remove thermal energy will be degraded.

The applicant has addressed these concerns via the generic approach developed for the Mark III Containment Issues Group (Reference 4.7.1). The key element

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of this study was the Perry Nuclear Plant 1/10-scale tests (Reference 4.7.2). In these tests, a number of related concerns were addressed systematically. These included short circuiting, development of bulk pool motion, ability to eliminate thermal stratification, and the presence of isolated recirculation zones.

The staff has reviewed this information in detail and has concluded that the Perry Nuclear Plant 1/10-scale tests correctly simulate design conditions in Mark III plants and, along with the other test information provided, include a sufficient range of parameters to encompass the Clinton plant-unique features. Since the findings from these tests show that good mixing can be achieved, as well as the absence of short circuiting, the staff concludes that the Clinton RHR system can be expected to perform in a manner consistent with design assumptions.

Conclusion

The staff considers the issues raised by these concerns satisfactorily resolved for Clinton.

References

4.7.1 Quadrex Corp., "A Survey of Tests and Analyses on the Effectiveness of the RHR System in the Pool Cooling Mode," Report No. QUAD-1-82-245, Rev. A, November 1982.

4.7.2 Gilbert Associates, Inc., "Model Study of Perry Nuclear Power Plant Suppression Pool - Final Report," November 1977.

HUMPHREY CONCERN 4.8

Operation of the RHR system in the containment spray mode will decrease the heat transfer coefficient through the RHR heat exchangers due to decreased system flow. The FSAR analysis assumes a constant heat transfer rate from the suppression pool, even with operation of the containment spray.

Evaluation

CIOG (using Grand Gulf as an example in an MP&L letter dated October 22, 1982) performed an analysis incorporating lower RHR heat exchanger heat transfer coefficients, resulting from operation of the containment spray system, into a realistic model both with and without full-capacity steam bypass of the drywell. Both cases demonstrated that containment design conditions were not exceeded.

A simple end-point calculation was performed by the review panel that has the advantage of removing the mitigating effects that the realistic assumptions had on the final results. The typical reduction in heat transfer capability due to spray actuation was determined to be approximately 8%. From the sensitivity studies performed to evaluate the impact of varying various input assumptions, the effect of reducing the RHR heat exchanger effectiveness by approximately 14% was to increase the peak suppression pool temperature by 6°F. Decreasing

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the heat exchanger capacity by 8% would then increase the suppression pool temperature by 3 to 5°F, which is insignificant when compared to the FSAR conservatisms identified in the response to Concern 4.4.

Both the realistic analysis performed by CIOG and the end-point calculation technique provided by the review panel shows that the effect of containment spray actuation on the suppression pool temperature is insignificant.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 4.9

The effect on the long-term containment response, and the operability of the spray system due to cycling the containment spray on and off to maximize pool cooling needs to be addressed. Also, provide and justify the criteria used by the operator for switching from the containment spray mode to pool cooling mode, and back again.

Evaluation

Humphrey implies that the RHR system with a decreased heat transfer capacity due to containment spray usage, and the most limiting single failure, will not be able to control the suppression pool temperature response to a DBA. However, the response to Concern 4.8 demonstrates that the RHR system, when limited as described above, can prevent the peak pool temperature from reaching the design limit of 185°F.

On the basis of the CIOG response to Concern 4.8, no need exists to provide specific criteria to switch from the containment spray mode to pool cooling mode in order to maintain the suppression pool temperature below the design limit.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 5.1

The worst case of drywell-to-containment bypass leakage has been established as a small break accident. An intermediate break accident will actually produce the most significant drywell-to-containment leakage prior to initiation of containment sprays.

Evaluation

The staff requires Mark III owners to consider the entire spectrum of break sizes in their analysis of the drywell steam bypass issue. The staff reviews the assumptions and results of the spectrum of break sizes as part of the normal FSAR review. The details of the staff's evaluation of this topic are contained in Clinton SER Section 6.2.1.7.

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The staff is satisfied that the entire range of break sizes has been considered in evaluating the consequences of drywell steam bypass.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 5.2

Under Technical Specification limits, bypass leakage corresponding to $A\sqrt{K} = 0.1$ ft^2 constitutes acceptable operating conditions. Smaller than intermediate break accident (IBA) sized breaks can maintain break flow into the drywell for long time periods, however, because the reactor vessel would be depressurized over a 6-hour period. Given, for example, a small-break accident (SBA) with $A\sqrt{K} = 0.1$, the projected time to reach 15 psig is 2 hours. In the latter 4 hours of the depressurization, the containment would presumably experience ever-increasing overpressurization.

Evaluation

The Mark III containment spray systems were specifically added to the Mark III design to remove the heat addition to the containment from suppression pool steam bypass leakages to an $A\sqrt{K}$ of approximately 1.0 ft^2, ten times higher than the Technical Specification value mentioned in the subject concern. Both the short-term and long-term effects of drywell steam bypass were evaluated by the applicant and reviewed by the staff, and found acceptable as part of the normal review process of the FSAR. Details of the staff's evaluation of this topic can be found in Section 6.2.1.7 of the SER. In addition, the operator is instructed to initiate rapid reactor vessel depression, and eliminate the driving pressure for steam bypass if the containment pressure increases beyond acceptable limits. This backup procedure, although not expected to be needed, reduces the need of the Mark III containment to cope with drywell steam bypass.

Further details of the staff's evaluation of this topic are contained in Section 6.2.1.7 of the SER.

Conclusions

The staff considers this issue closed.

HUMPHREY CONCERN 5.3

Leakage from the drywell to containment will increase the temperature and pressure in the containment. The operators will have to use the containment spray in order to maintain containment temperature and pressure control. Given the decreased effectiveness of the RHR system in accomplishing this objective in the containment spray mode, the bypass leakage may increase the cyclical duty of the containment sprays.

Evaluation

The design, testing, and maintenance of the active portions of the RHR spray train to pool cooling systems provide confidence that the components should function. Furthermore, the switching process is not expected to challenge the ability of the individual components to perform their functions. In addition, the analysis performed for Humphrey Concern 4.8 shows that the containment sprays can be operated continuously without adverse consequences on the pool temperature response.

The high quality of components, in conjunction with the analysis that demonstrates RHR mode switching will not be required, resolves this issue in the opinion of the staff.

Conclusions

The staff considers this issue closed.

HUMPHREY CONCERN 5.4

Direct leakage from the drywell to the containment may dissipate hydrogen outside the region where the hydrogen recombiners take suction. The anticipated leakage exceeds the capacity of the drywell purge compressors. This could lead to pocketing of hydrogen exceeding the concentration limit of 4% by volume.

Evaluation

The staff assumes this concern relates to conditions associated with a DBA-LOCA, and not for the large metal-water reaction included in the 1985 rule change to 10 CFR 50.44.

The Clinton design does not purge the drywell with containment air, but takes suction from the drywell and discharges to the wetwell through the suppression pool. This arrangement tends to reduce the bypass leakage driving potential and the amount of hydrogen leakage. The electrical penetrations are considered potential leakage paths. However, they are shown to be at plant elevations which are beneath the recombiner suction points. The potential for hydrogen pocketing near the electrical penetrations is expected to be very small, as no physical obstructions are present to induce such pocketing.

Conclusion

The staff considers this issue satisfactorily resolved for Clinton.

HUMPHREY CONCERN 5.5

Equipment may be exposed to local conditions which exceed the environmental qualification envelope as a result of direct drywell-to-containment bypass leakage.

Evaluation

Following a LOCA or a main steamline break, the drywell temperature can reach temperatures in excess of 300°F. The concern is that the resulting superheated air/steam gas could pass through drywell bypass leakage paths and impinge on safety-related equipment located in the containment near the drywell wall. The applicant has provided a list of the safety-related equipment within 10 feet of the drywell electrical penetrations, which are the bypass paths assumed to exist for this analysis. The applicant has determined that those equipment items not qualified for the drywell temperature profile are located at least 4 feet from the drywell penetration, and on or below the elevation of the drywell penetrations. This minimum spacing will be more than sufficient, according to the applicant, to diffuse any drywell air passing through the 3.5-inch-diameter electrical cable penetrations in the 5-foot-thick drywell wall.

The staff agrees that there will be a considerable amount of cooling of the drywell air as it passes through the postulated drywell leakage paths because of the thickness of the wall and the relatively small leakage areas that could conceivably occur. The drywell concrete wall, including the drywell wall penetrations, is designed to be a leaktight barrier under all accident conditions and directs the steam produced by a DBA LOCA or MSLB into the suppression pool. Thus, the staff does not believe it credible to postulate through-wall large cracks in the drywell wall or around penetrations that could lead to significant amounts of drywell air to enter the containment at the superheated temperatures postulated by Humphrey.

The information submitted by the applicant, relative to the location and qualification criteria for safety-related equipment located near the drywell electrical penetrations, provides additional assurance that there will be no adverse effects on the safety of the plant from the local high temperature effects from steam bypass postulated by Humphrey.

Conclusion

The staff considers this issue satisfactorily resolved for Clinton.

Reference

5.5.1 IPC letter No. U-0714 dated May 25, 1984, from D. I. Herborn (IPC) to A. Schwencer (NRC).

HUMPHREY CONCERNS 5.6 AND 9.2

5.6 The test pressure of 3 psig specified for the periodic operational drywell leakage rate tests does not reflect additional pressurization in the drywell which will result from upper pool dump. This pressure also does not reflect additional drywell pressurization resulting from throttling of the ECCS to maintain vessel level which is required by the current EPGs.

9.2 The continuous steaming produced by throttling the ECCS flow will cause increased direct leakage from the drywell to the containment. This could result in increased containment pressure.

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Evaluation

The staff agrees that, under the conditions postulated by Humphrey, a pressure differential greater than the 3 psi used in the periodic operational drywell leakage rate tests could exist for a period of time for small steamline breaks. However, the maximum possible increase in the differential pressure due to the scenario postulated by Humphrey is approximately twice the test pressure, which would result in approximately twice the steam bypass leakage to the containment. The acceptance criteria for the periodic 3-psi pressure differential test is 10% of the allowable bypass leakage. The large margin in the periodic test acceptance criteria is more than enough to offset the potential bypass leakage increases due to the increased differential pressure from upper pool dump and ECCS throttling. All Mark III plants are required to use a bypass leakage capability that is approximately 10 times greater than the periodic 3-psi pressure differential test acceptance criteria to demonstrate that the Mark III containment can withstand the maximum conceivable drywell steam bypass leakage.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 5.7

After upper pool dump, the level of the pool will be 6 feet higher, and drywell-to-containment differential pressure will be greater than 3 psi. The drywell hydrogen purge compressor head is 6 psi. The concern is that after an upper pool dump, the purge compressor head may not be sufficient to depress the weir annulus enough to clear the upper vents. In such a case, hydrogen mixing would not be achieved.

Evaluation

The applicant has noted that after the upper pool dump, the level of the suppression pool will increase less than 2 feet. The hydrogen compressors used at Clinton have a discharge head of 4.5 psi. The two compressors are adequately sized to overcome the additional pressure which is caused by the upper pool dump. The compressors take suction off the top of the drywell and exhaust below the suppression pool water surface in the containment.

Conclusion

On the basis of the discussion provided above, the staff considers this issue satisfactorily resolved for Clinton.

HUMPHREY CONCERN 5.8

The possibility of high temperatures in the drywell without reaching the 2-psig high-pressure scram level because of bypass leakage through the drywell wall, should be addressed.

Evaluation

The concern is that bypass leakage from the drywell during a transient that adds heat to the drywell (e.g., a small main steamline break) will reduce the drywell atmospheric mass, thus allowing high temperatures to exist without actuating the automatic reactor scram signals. The net result could be higher than design temperatures inside the drywell before actions are performed to mitigate the accident consequences.

To evaluate this possibility, CIOG analyzed (MP&L letter dated December 3, 1982) a spectrum of break sizes assuming full-capability bypass leakage, heat transfer to the drywell heat sinks, and conservative initial conditions. The bypass leakage used is very conservative, being approximately 10 times greater than the Technical Specification value. A 10-minute interval was assumed for operator action to detect and manually respond to the transient. The limiting break size case resulted in a peak drywell temperature at 10 minutes of 246°F, which is well below the drywell design temperature of 330°F.

CIOG also provided (MP&L letter dated December 3, 1982) a detailed description of the instrumentation and alarms available to inform the control room operator of high drywell temperature conditions and the probable cause of the temperature transient. The operators will be able to distinguish between loss of drywell air coolers and small breaks in the reactor coolant system by using the instrument readouts and alarms for high drywell radiation, drywell pump levels, and narrow range drywell pressure indications.

In addition, analyses performed for the River Bend plant (NUREG-0989, Supp. 2), a plant generally applicable to the other Mark III plants for this Humphrey concern, shows that for even very small break sizes (0.008 ft^2) the 2-psig scram setpoint will be reached before drywell temperatures exceed design temperatures.

The analysis performed shows that adequate time and information exists to alert the operator to take the appropriate actions to prevent drywell temperatures from exceeding design values and, also that the 2-psig setpoint would automatically scram the plant before drywell temperatures reached the design value of 330°F.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 6.1

GE has recommended that the drywell purge compressors and the hydrogen recombiners be activated if the reactor vessel water level should drop to within 1 foot of the top of active fuel. This requirement was not incorporated in the emergency procedure guidelines.

Evaluation

The current emergency procedure guidelines, as approved by the NRC, require control room operators to initiate the drywell mixing system when the drywell

hydrogen concentration reaches 3% by volume. The concern raised by Humphrey has an involved history that is fully explained in the Review Panel's report [letter dated July 27, 1984, from L. A. England to H. R. Denton (NRC)]. Basically, this recommendation originated during informal discussions held between GE and the NRC staff in 1981 on how to ensure timely initiation of the drywell purge compressors. At that time, the staff had expressed concerns about the hydrogen monitoring system's ability to measure the hydrogen concentration when the drywell atmosphere consisted of all steam (see Humphrey Concern 4.6). The recommendation outlined in this Humphrey concern was the proposed solution to the staff concern. However, none of the Mark III plants utilize hydrogen-monitoring systems that have the limitation of the GE hydrogen monitors. Therefore, this recommendation to initiate the drywell compressors based on the reactor vessel water level is no longer relevant to the design-basis accident hydrogen control issue.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 6.2

GE has recommended that an interlock be provided to require containment spray prior to starting the recombiners because of the large quantities of heat input to the containment. Incorrect implementation of this interlock could result in the inability to operate the recombiners without containment spray.

Evaluation

None of the Mark III plants have an interlock to require containment spray before starting the recombiners. This interlock recommendation was based on a design feature that was removed from the Mark III containment concept early in the design process. The staff agrees that the current Mark III design does not need spray actuation before recombiner initiation and considers this issue not applicable to any Mark III plant under licensing review.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERNS 6.3 AND 6.5

6.3 The recombiners may produce "hot spots" near the recombiner exhausts that might exceed the environmental qualification envelope or the containment design temperature.

6.5 Discuss the possibility of local temperatures due to recombiner operation being higher than the temperature qualification profiles for equipment in the region around and above the recombiners. State what instructions, if any, are available to the operator to actuate containment sprays to keep this temperature below design values.

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Evaluation

The applicant has noted that the hydrogen recombiner is outside of the containment. The control building heating, ventilation, and air conditioning (HVAC) system removes most of the recombiner heat which results in the return flow to the containment having a temperature less than 150°F, and is no threat to containment integrity or any safety-related equipment in the region around the recombiner exhaust. The staff concludes that the Clinton 150°F recombiner return temperature is comfortably below the 185°F or higher used for equipment and containment design.

Conclusion

The staff considers this issue satisfactorily resolved for Clinton.

HUMPHREY CONCERN 6.4

For the containment air monitoring system furnished by GE, the analyzers are not capable of measuring hydrogen concentration at volumetric steam concentrations above 60%. Effective measurement is precluded by condensation of steam in the equipment.

Evaluation

None of the Mark III plants utilize the containment air monitoring system furnished by GE. In addition, the systems selected by the Mark III plants are designed to operate under all volumetric steam concentrations inside the drywell.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 7.1

Refer to Humphrey Concern 4.4.

HUMPHREY CONCERN 7.2

The computer code used by GE to calculate environmental qualification parameters considers heat transfer from the suppression pool surface to the containment atmosphere. This is not in accordance with the existing licensing basis for Mark III environmental qualifications. Additionally, the bulk suppression pool temperature was used in the analysis instead of the suppression pool surface temperature.

Evaluation

The GE containment response computer code SHEX was only used to identify the margins in the results of using the staff's environmental qualification profile methodology contained in NUREG-0588. All Mark III plants have used the

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NUREG-0588 qualifications parameters in the development of plant-unique environmental qualification curves, which the staff finds acceptable.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 7.3

The analysis assumes that the containment air space is in thermal equilibrium with the suppression pool. In the short term, this is nonconservative for the Mark III containment design due to adiabatic compression effects and finite time required for heat and mass to be transferred between the pool and containment volumes.

Evaluation

The effect of the adiabatic compression effect has been calculated by CIOG to be about 0.5 psi. This slight increase has no design significance for the Mark III containment because the limiting conditions for containment pressure buildup are reached in the long term, after this effect is completely gone.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 8.1

This issue is based on consideration that some Technical Specifications allow operation at parameter values that differ from the values used in assumptions for FSAR transient analyses. Normally, analyses are done assuming a nominal containment pressure equal to ambient (0 psig), and a temperature near maximum operating temperature (90°F), and do not limit the drywell pressure equal to the containment pressure. The Technical Specifications permit operation under conditions such as a positive containment pressure (1.5 psig), and temperatures less than maximum (60 or 70°F), and drywell pressure can be negative with respect to the containment (-0.5 psid). All of these differences would result in transient responses different than the FSAR descriptions.

Evaluation

The basic question raised by Humphrey is: "Have all the worst-case combinations of initial conditions been considered in the FSAR analysis?" The staff has considered the effects of initial conditions on the end-results of various accidents for many years, and has developed criteria for evaluating the initial conditions selected by applicants. Basically, the staff's approach to this concern can be summarized as follows:

(1) Numerous analyses using computer codes developed to predict the plant response to various accident scenarios have shown which initial condition variations have a strong effect on the end-results.

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(2) If the initial conditions have a significant impact on the end-results, then the staff requires that the most limiting value be used in the analysis. An example of this is the use of zero relative humidity in subcompartment analyses.

(3) If the initial conditions do not have much of an impact on the end-results, the staff requests the applicant to use generally conservative values or expected values for the initial conditions. An example of this would be the effect of initial drywell temperatures on the peak calculated drywell temperatures.

(4) The margins that exist between the peak calculated values and the design values are intended, in part, to account for the uncertainties in the assumptions, and analytical techniques utilized in the response analysis, including the uncertainties inherent in the initial conditions.

In direct response to Humphrey's concern, the applicant has referenced the MP&L sensitivity study (Reference 8.1.1) involving drywell and containment initial conditions similar to those at Clinton, which affect the design basis accident (DBA) long-term containment response. The results show that the containment design pressure is not exceeded

The staff recognizes the analytical techniques employed by the applicant are conservative, and there is significant margins between the peak calculated containment pressure and the design pressure.

Conclusion

The staff considers this issue satisfactorily resolved for Clinton.

Reference

8.1.1 MP&L AECM-83/574, Item 2 of Action Plan 25.

HUMPHREY CONCERNS 8.2 AND 8.3

8.2 The draft Grand Gulf Technical Specifications permit operation of the plant with containment pressure ranging between 0 and -2 psig. Initiation of containment spray at a pressure of -2 psig may reduce the containment pressure by an additional 2 psig, which could lead to buckling and failures in the containment liner plate.

8.3 If the containment is maintained at -2 psig, the top row of vents could admit blowdown to the suppression pool during a small-break accident (SBA) without a LOCA signal being developed.

Evaluation

The proposed Clinton Technical Specification 3.6.1.6 limits the containment pressure range to -0.25 psid to +0.25 psid. Inadvertent containment spray actuation is addressed in Section 6.2.1.5 of the SER, and also under Humphrey Concern 8.4.

Conclusion

The staff considers these issues closed.

HUMPHREY CONCERN 8.4

Describe all of the possible methods, both before and after an accident, of creating a condition of low air mass inside the containment. Discuss the effects on the containment design external pressure of actuating the containment sprays.

Evaluation

The containment negative pressure evaluation is described in Clinton FSAR Section 6.2.1.1.4.2.

The design-basis transients that could result in significant negative pressure within the containment involve the inadvertent actuation of the containment spray while the containment atmosphere is at high temperature and humidity, and inadvertent spray actuation following a reactor water cleanup (RWCU) line break. The applicant has determined that the greatest negative pressure condition would occur if there is a break in the reactor water cleanup (RWCU) system followed by actuation of the containment spray. The initial conditions in the containment were assumed to be 14.7 psia, 104°F, and 60% relative humidity. The spray water was assumed to be at a temperature of 60°F. The applicant also assumed that the vacuum relief valves permitted flow only from the containment to the drywell.

The break in the RWCU system results in a peak estimated containment pressure of less than 2 psig with a temperature of 112°F and a relative humidity of 100% at the time of spray initiation. The applicant calculated a negative overall containment differential pressure of less than 2.2 psi, which is less than the 3.0 psi negative limit determined by the liner plate deformation without exceeding the allowable stress level.

The staff has also evaluated this issue in Section 6.2.1.5 of the SER.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 9.1

Refer to Humphrey Concern 4.2.

HUMPHREY CONCERN 9.2

Refer to Humphrey Concern 5.6.

HUMPHREY CONCERN 9.3

It appears that some confusion exists as to whether SBAs and stuck-open SRV accidents are treated as transients or design-basis accidents. Clarify how they are treated, and indicate whether the initial conditions were set at nominal or licensing values.

Evaluation

CIOG has stated that SBAs and stuck-open SRV accidents are treated as design-basis accidents. The initial conditions used in the analysis of these accidents are the same conservative licensing values used for the double-ended rupture of a recirculation pipe.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 10.1

The suppression pool may overflow from the weir wall when the upper pool is dumped into the suppression pool. Alternatively, negative pressure between the drywell and the containment that occurs as a result of normal operation, or sudden containment pressurization, could produce a similar overflow. Any cold water spilling into the dryweil and striking hot equipment may produce thermal failures.

Evaluation

The applicant has conducted an analysis to determine whether overflow of the weir wall occurs at the vacuum breaker pressure differential setpoint of 0.2 psi. The conditions used to perform these calculations were: (a) high suppression pool level of 731 feet 5 inches, (b) high upper containment pool level of 827 feet 4 inches (1 inch above high-water level), and (c) drywell negative pressure differential of -0.2 psi. These calculations showed that the water level stayed well below the top of the weir wall after upper pool dump (735 feet 9 inches).

Conclusion

The staff considers this issue closed.

Reference

10.1.1 IPC letter No. U-0562 dated November 23, 1982, from G. E. Wuller (IPC) to C. O. Thomas (NRC).

HUMPHREY CONCERN 10.2

Describe the interface requirement (A42) that specifies that no flooding of the drywell shall occur. Describe your intended methods to follow this interface.

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Evaluation

The interface requirement specifying that no drywell flooding shall occur is as follows:

> The suppression pool weir wall height shall provide sufficient free-board volume to accept a dump of the upper pool without resulting in overflow flooding into the drywell. The free-board height shall be measured between the top of the weir wall and high water level (HWL) which is 7'6" above the top vent centerline.

The staff has evaluated each of the Mark III owners (CIOG) intentions to follow this interface requirement under Humphrey Concern 10.1.

The interface requirement addresses inadvertent upper pool dump, which is discussed under Humphrey Concern 10.1.

Conclusion

The staff considers this issue closed.

Reference

10.2.1 IPC letter No. U-0596 dated February 4, 1983, from G. E. Wuller (IPC) to A. Schwencer (NRC).

HUMPHREY CONCERN 11.0

Mark III load definitions are based upon the levels in the suppression pool and the drywell weir annulus being the same. The Grand Gulf Technical Specifications permit elevation differences between these pools. This may affect load definition for vent clearing.

Evaluation

CIOG evaluated the effect of having a higher initial pressure in the containment than in the drywell on the load definitions for vent clearing. For pressure differentials in the other direction, the staff agrees that the vent clearing loads will be less severe than normal because the vents will clear sooner. The Technical Specification maximum values of the differentials pressure are used by CIOG in its analyses of the change in peak drywell pressure. The drywell pressure increase was about 1%, which is a negligible change.

The staff finds the effect of differential pressures between the drywell and containment to be negligible for the Mark III plants.

Conclusion

The staff considers this issue closed.

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HUMPHREY CONCERN 12.0

The upper pool dumps into the suppression pool automatically following a LOCA signal with a 30-minute-delay timer. If the signal that starts the timer disappears on the solid state logic plants, the timer resets to zero preventing upper pool dump.

Evaluation

Clinton has completed a design change to "seal-in" the LOCA signal.

Conclusions

The staff considers this issue closed.

HUMPHREY CONCERN 13.0

The "B" loop of the containment sprays includes a 90-second timer to prevent simultaneous initiation of the redundant containment sprays. Because of instrument drift in the sensing instrumentation and the timers, GE estimates that there is a 1 in 8 chance that the sprays will actuate simultaneously. Simultaneous actuation could produce negative pressure transients in the containment, and aggravate temperature stratification in the suppression pool.

Evaluation

The analysis performed at Mark III plants to evaluate the effort of inadvertent containment spray initiation considers both spray trains initiating simultaneously. Therefore, this Humphrey concern is implicitly accounted for in the current FSAR analysis.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 14.0

A failure in the check valve in the LPCI line to the reactor vessel could result in direct leakage from the pressure vessel to the containment atmosphere. This leakage might occur as the LPCI motor-operated isolation valve is closing, and the motor-operated isolation valve in the containment spray line is opening. This could produce unanticipated increases in the containment pressure.

Evaluation

The scenario postulated by Humphrey requires a highly improbable sequence of events to occur. The break size in the reactor coolant system has to be large enough to introduce significant amounts of steam into the drywell, yet small enough so that the reactor vessel still has considerable pressure (300 to 400 psi) at the time the sprays would be actuated. The check valve in the train

that is being transferred to the containment spray mode must fail. The possibility of this Humphrey concern occurring as a result of manual actuation of the containment spray can be ruled out because the operator is directed to secure the RHR loop to the reactor vessel before opening the valve admitting water to the containment spray headers. Failure of the operator to perform this written procedure correctly in conjunction with a failure of the check valve in the proper train is too improbable to be considered.

Automatic initiation of the transfer process would then have to occur for the Humphrey concern to happen, which means the containment pressure would have to reach 9 psig early in the transient (or the reactor vessel pressure will be too low to produce significant steam backflow through the RHR line). To reach 9 psig early in the transient, a significant amount of drywell steam bypass had to occur, which makes the chance of this sequence even more unlikely.

At the request of the staff, CIOG analyzed the consequences should this Humphrey concern occur. The transfer to the containment spray mode is assumed to occur when the reactor vessel pressure is equal to the RHR pump shutoff head, and the valve operating times used are representative of the startup test results for Grand Gulf, and justified to be applicable to Clinton. Because manual transfer to containment sprays was ruled out, as explained above, the scenario was started with the containment pressure equal to 9 psig, the setpoint for automatic transfer to the containment spray mode. Automatic transfer at higher containment pressures would require additional failures in the plant safety system, and is not considered to be credible.

The pressure increase, resulting from the steam addition to the containment airspace from the backflow through the containment spray headers during the time interval of the valves being open, was calculated to be 0.8 psi. This small increase does not impact the design pressure of 15 psig since the total pressure would be less than 10 psig for this scenario. The large margin, 5 psig, is more than sufficient to cover the possible uncertainties in the applicant's analysis.

The analysis performed by CIOG demonstrates that this Humphrey concern does not challenge the design of the Mark III containment.

Conclusion

The staff considers this issue closed.

Reference

14.0.1 IPC letter No. U-0615 dated March 17, 1983, from G. E. Wuller (IPC) to A. Schwencer (NRC).

HUMPHREY CONCERN 15.0

The STRIDE plants had vacuum breakers between the containment and the secondary containment. With sufficiently high flows through the vacuum breakers to containment, vacuum could be created in the secondary containment.

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Evaluation

This concern is not applicable to the containment vacuum system at Clinton because the outside air, not the secondary containment air, is used as a source of makeup air to the containment.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 16.0

Some of the suppression pool temperature sensors are located (by GE recommendation) 3 to 12 inches below the pool surface to provide early warning of high pool temperature. However, if the suppression pool is drawn down below the level of the temperature sensors, the operator could be misled by erroneous readings, and the required safety action could be delayed.

Evaluation

The applicant committed to include in the plant emergency procedures either a requirement that the operator verify level in the suppression pool before reading suppression pool temperatures, or specify which suppression pool temperature instruments can be used following an accident. The staff believes either of these approaches will prevent erroneous readings on the part of the operator and, therefore, are acceptable.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 17.0

The EPGs contain a curve which specifies limitations on suppression pool level and reactor pressure vessel pressure. The curve presently does not adequately account for upper pool dump. At present, the operator would be required to initiate automatic depressurization when the only action required is the opening of one additional SRV.

Evaluation

The draft Technical Specification limits the suppression pool water to 19.42 feet for continuous operation. The maximum allowable suppression pool water level at the reactor pressure of 1,165 psig is 21.42 feet. If there is an upper pool dump, the suppression water level will rise from 19.42 feet to 21.34 feet. Therefore, the suppression pool level will not exceed the maximum allowable even after an upper pool dump. The possibility of operator action, as suggested, would never occur.

Conclusion

The staff considers this issue satisfactorily resolved for Clinton.

Reference

17.0.1 IPC letter No. U-0562 dated November 23, 1982, from G. E. Wuller (IPC) to C. Thomas (NRC).

HUMPHREY CONCERN 18.1

Failures of reflective insulation in the drywell may lead to blockage of the gratings above the weir annulus. This may increase the pressure required in the drywell to clear the first row of drywell vents and perturb the existing load definitions.

Evaluation

The applicant has performed an analysis which indicates that failure of the reflective insulation in the drywell would not significantly block grating flow passage loading to the weir annulus. The maximum area that the failed insulation could cover is 207 ft^2. Jet sprays would compact this insulation in a localized area being 70 ft^2. This leaves 420 ft^2 for flow area plus an additional 200 ft^2 of vertical clearance between the grating and the weir wall. Coupling this 620 ft^2 with the weir annulus floor area of 455 ft^2 indicates that there should be no significant blockage of flow area.

Conclusion

The staff considers this issue satisfactorily resolved for Clinton.

HUMPHREY CONCERN 18.2

Insulation debris may be transported through the vents in the drywell wall into the suppression pool. This debris could then cause blockage of the suction strainers.

Evaluation

This concern is addressed in Section 6.2.2 of Appendix C to the Clinton SER, and Generic Letter 85-22 which resolves Unresolved Safety Issue (USI) A-43. The conclusion reached by the staff is that the design minimized the potential of clogging the pump suction strainers, and that there is reasonable assurance Clinton can be operated without endangering the health and safety of the public.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 19.1

The chugging loads were originally defined on the basis of 7.5 feet of submergence over the drywell to suppression pool vents. Following an upper pool dump, the submergence will actually be 12 feet which may affect chugging loads.

Evaluation

The applicant's response to this concern is based on the generic response which was originally provided by MP&L for Grand Gulf via Reference 19.1.1. In this submittal, arguments based upon physical and analytical procedures were used to estimate the pressure field principles that would be generated on the suppression pool boundaries if the worst-case chug from the Mark III data base were to occur with the top vent at a 12-foot submergence. The results are compared with design on an ARS basis and shown to be bounded, except for local loads in the frequency range 12 to 32 Hz. For these conditions an exceedance of design loads amounting to 35% occurs on the basemat.

The applicant argues that this exceedance is not important because this is a local load affecting only the basemat liner, and that because of the hydrostatic head to which the liner is subjected, it will not experience a "negative pressure in the frequency range of exceedance." Also, "since the liner is backed by concrete everywhere, no natural modes in this range are excitable."

The staff notes the following:

- The increase in submergence due to upper pool dump for Clinton is only about 2 feet (Reference 19.1.2) compared to 4½ feet for Grand Gulf.
- Chugging loads would be correspondingly reduced.
- The use of an acoustic model in the analysis represents a significant conservatism.
- Dissipative mechanisms not accounted for in such an analysis result in pressure attenuation which is much greater than predicted; this has been borne out convincingly by experimental results.
- Application of the worst-case chug to all vents, which is done for local loads, also represents a very significant conservatism.
- In a recent submittal for the Perry Nuclear Plant to address the staff concern relative to the combined effect of upper pool dump and encroachment on local chugging loads (Reference 19.1.3), it was shown that by postulating a maximum strength chug at the central vent and an average strength chug at adjacent vents, the design loads were capable of bounding the combined effect.

In summary, the margins inherent in the design loads for chugging are very large. They can more than accommodate any increment in loading caused by off-design effects such as increased submergence due to upper pool dump.

Conclusion

The staff considers this issue satisfactorily resolved for Clinton.

References

19.1.1 MP&L letter No. AECM-82/353 dated August 19, 1982, from L. F. Dale (MP&L) to H. R. Denton (NRC).

19.1.2 IPC letter No. U-600319 dated November 25, 1985, from F. A. Spangenberg (IPC) to W. R. Butler (NRC).

19.1.3 CEI letter dated July 11, 1984, from M. R. Edelman (CEI) to B. J. Youngblood (NRC).

HUMPHREY CONCERN 19.2

The effect of local encroachments on chugging loads needs to be addressed.

Evaluation

The applicant's response to this concern is generic, and was originally provided by MP&L for Grand Gulf via Reference 19.2.1. In this submittal, physical principle arguments and analytical procedures are used to estimate the pressure field that would be generated on the suppression pool boundaries if the worst-case chug from the Mark III data base were to occur at vents located below the Grand Gulf traversing incore probe (TIP) platform. The results are compared with design loads on an ARS basis and shown to be bounded except for local loads in the frequency range 12 to 30 Hz. For these conditions, an exceedance of design amounting to 60% would occur on the basemat.

The applicant argued that this exceedance is not important because this is a local load affecting only the basemat liner, and that because of the hydrostatic head to which the liner is subjected, it will not experience a "negative pressure in the frequency range of exceedance." Also, "since the liner is backed by concrete, no natural modes in this range are excitable."

The staff notes the following:

- The loads developed for Grand Gulf are conservative for Clinton, as indicated in their respective responses to Humphrey Concern 1.0, the Grand Gulf TIP platform represents a much larger encroachment than any in Clinton.
- The use of an acoustic model in the analysis represents a significant conservatism.
- Dissipative mechanisms not accounted for in such an analysis result in pressure attenuation which is much greater than predicted; this has been borne out convincingly by experimental results.
- Application of the worst-case chug to all vents below the encroachment also represents a very significant conservatism.

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In a recent submittal for the Perry Nuclear Plant to address the staff concern relative to the combined effect of upper pool dump and encroachment on local chugging loads (Reference 19.2.2), it was shown that by postulating a maximum strength chug at the central vent and average strength chug at adjacent vents, the design loads were capable of bounding the combined effect.

In summary, the margins inherent in the design loads for chugging are very large. They can more than accommodate any increment in loading caused by off-design effects such as encroachment.

Conclusion

The staff is satisfied that the issues related to this concern have been satisfactorily addressed by the applicant and are, therefore, considered closed.

References

19.2.1 MP&L letter No. AECM-82/374 dated December 3, 1983, from L. F. Dale (MP&L) to H. R. Denton (NRC).

19.2.2 CEI letter dated July 11, 1984, from M. R. Edelman (CEI) to B. J. Youngblood (NRC).

HUMPHREY CONCERN 20.0

During the latter stages of a LOCA, ECCS overflow from the primary system can cause drywell depressurization and vent overflow. The GESSAR defines vent backflow, vertical impingement, and drag loads to be applied to drywell structures, piping, and equipment, but no horizontal loading is specified.

Evaluation

The reverse weir annulus flow will be directed vertically into the drywell. The only horizontal flow possible would be deflection of the rising water off structures above the weir wall, or from the gravity-induced lateral velocity gradients in the vertically rising water. Deflection of the vertically rising water would result in a spray type of impact load, which is not expected to result in any significant loads. The lateral movement of the rising water resulting from gravity is expected to be slight and not create any significant horizontal loads.

The staff does not consider it credible that the slight horizontal loads would be bounding loads on structures inside the drywell because of all the other load constraints on these structures, such as earthquake loads, reactor vessel blowdown loads, and dead loads.

Conclusion

The staff considers this issue closed.

HUMPHREY CONCERN 21.0

Regulatory Guide 1.7 requires a backup purge hydrogen removal capability. This backup purge for Mark III is via the drywell purge line which discharges to the shield annulus, which in turn is exhausted through the standby gas treatment system. The containment air is blown into the drywell via the drywell purge compressor to provide a positive purge. The compressors draw from the containment. However, without hydrogen-lean air makeup to the containment, no reduction in containment hydrogen concentration occurs. It is necessary to ensure that the shield annulus volume contains a hydrogen-lean mixture of air to be admitted to the containment via containment vacuum breakers.

Evaluation

This issue is not applicable to Clinton because containment vacuum breakers are not included in the Clinton design.

Conclusion

The staff considers this issue closed for Clinton.

HUMPHREY CONCERN 22.0

The EPGs currently in existence have been prepared with the intent of coping with degraded core accidents. They may contain requirements conflicting with design basis accident conditions. Someone needs to carefully review the EPGs to assure that they do not conflict with the expected course of the design basis accident.

Evaluation

The emergency procedures guidelines (EPGs) have been prepared with the intent of coping with all types of accidents, including design-basis accidents, degraded core accidents, and accidents involving multiple failures.

The process of developing the EPGs includes input from experienced personnel from all utilities that own BWR plants and representatives from GE. The NRC has reviewed, and is continuing to review, the latest version of the EPGs to ensure to the maximum extent possible that no conflicts exist between the EPGs and the licensing basis accident analysis.

The staff is satisfied with the steps that have been taken in development of the EPGs and also in the ongoing review process to assure consistency in the EPGs.

Conclusion

The staff considers this issue closed.

ADDITIONAL CONCERNS

Questions relating to two additional concerns were developed by BNL. Although they have evolved from and are related to Humphrey Concern 19.0, they are not officially recognized as Humphrey concerns. To facilitate future reference, the staff uses the identifiers BNL-1 and BNL-2, to denote these concerns.

BNL-1

The effects of increased submergence and encroachment on local loads are additive. ARS comparisons showing the combined effect should be provided.

Evaluation

A generic response was developed for this concern and included in an earlier submittal for the Perry Nuclear Plant (Reference B.1.1). As indicated in the evaluation provided for Humphrey Concerns 19.1 and 19.2 above, by postulating the very reasonable assumption that a maximum strength chug occurred only at a central vent with average strength chugs at surrounding vents, local loads were estimated at levels which were adequately bounded by design.

Conclusion

The utilities have provided an adequate demonstration that the design load for chugging has sufficient margin to accommodate the increment in loading caused by the combined effects of encroachment and increased submergence. The staff considers this issue to be closed.

Reference

B.1.1 CEI letter No. PY-CEI/NRR-0123L dated July 11, 1984, from M. R. Edelman (CEI) to B. J. Youngblood (NRC).

BNL-2

Upper pool dump increases the length of the water column within the main steam SRVDL. This will tend to increase pipe thrust loads during SRV actuation. Provide an analysis to this effect.

Evaluation

The applicant states in Reference B.2.1 that the SRVDLs have been designed to accommodate a subsequent actuation level which is 6 feet above the normal suppression pool level. Accordingly, the increase due to upper pool dump is "within design consideration for the SRV lines."

Conclusion

On the basis of the statement made by the applicant, the staff considers this concern to be resolved.

Reference

B.2.1 IPC letter No. U-600319 dated November 25, 1985, from F. A. Spangenberg (IPC) to W. R. Butler (NRC).

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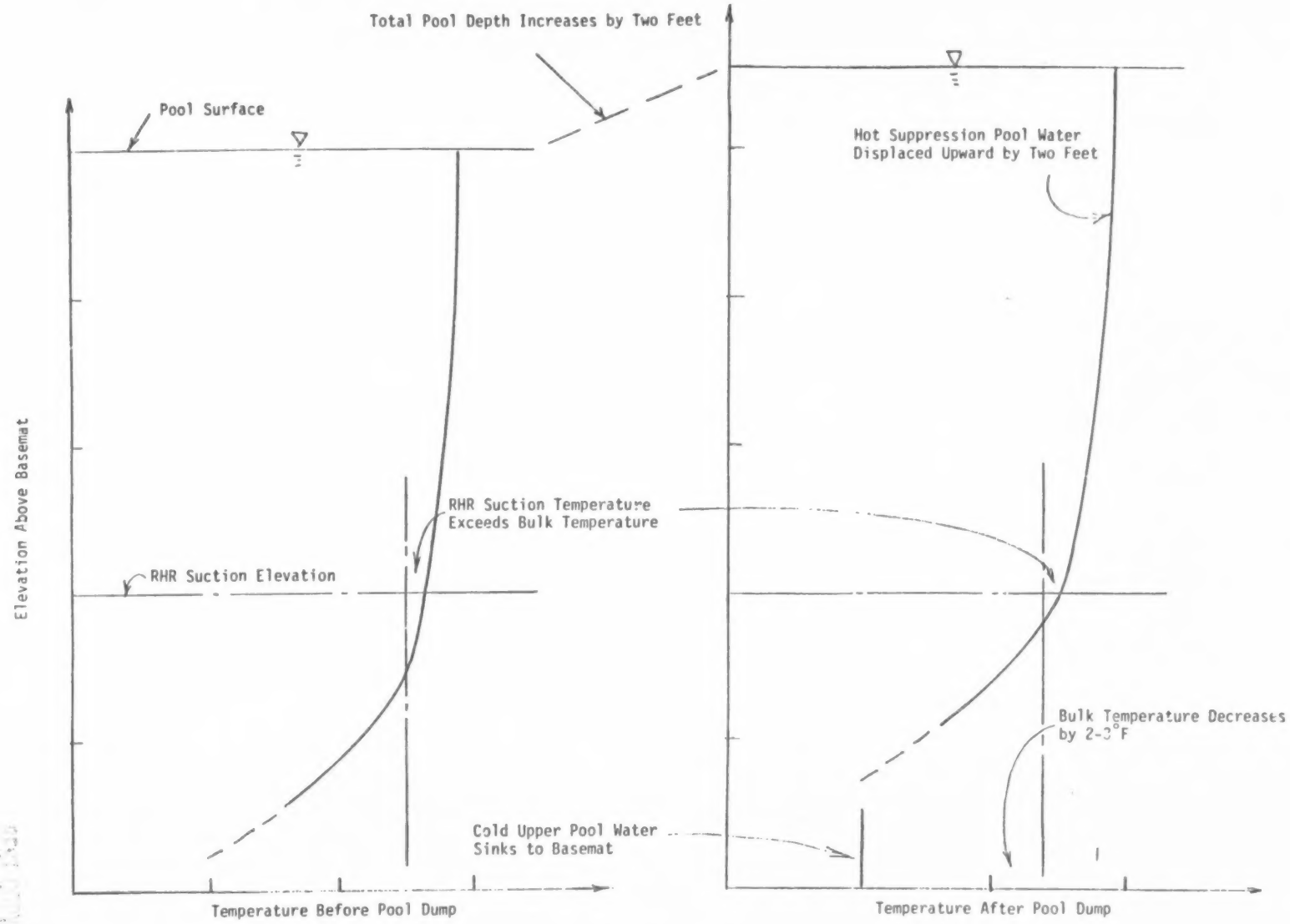

Figure 4.5.1 Bounding Scenario for Clinton Upper Pool Dump

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13. ABSTRACT (200 words or less)

Supplement No. 6 to the Safety Evaluation Report on the application filed by Illinois Power Company, Soyland Power Cooperative, Inc., and Western Illinois Power Cooperative, Inc., as applicants and owners, for a license to operate the Clinton Power Station, Unit No. 1, has been prepared by the Office of Nuclear Reactor Regulation of the U. S. Nuclear Regulatory Commission. The facility is located in Harp Township, DeWitt County, Illinois. This supplement reports the status of items that have been resolved by the staff since Supplement No. 5 was issued.

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